APACHE CORP
Form 10-Q
May 03, 2018
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)
ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2018
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission File Number 1-4300
APACHE CORPORATION
(exact name of registrant as specified in its charter)

Delaware	41-0747868
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

One Post Oak Central, 2000 Post Oak Boulevard, Suite 100, Houston, Texas 77056-4400
(Address of principal executive offices)
Registrant’s Telephone Number, Including Area Code: (713) 296-6000

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 ý No ¨
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 ý No ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and “emerging growth company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer	ý	Accelerated filer	¨
Non-accelerated filer	¨ (Do not check if a smaller reporting company)	Smaller reporting company	¨
		Emerging growth company	¨

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No ý
Number of shares of registrant’s common stock outstanding as of April 30, 2018 382,154,292

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Forward-Looking Statements and Risk

This report includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included or incorporated by reference in this report, including, without limitation, statements regarding our future financial position, business strategy, budgets, projected revenues, projected costs, and plans and objectives of management for future operations, are forward-looking statements. Such forward-looking statements are based on our examination of historical operating trends, the information that was used to prepare our estimate of proved reserves as of December 31, 2017, and other data in our possession or available from third parties. In addition, forward-looking statements generally can be identified by the use of forward-looking terminology such as “may,” “will,” “could,” “expect,” “intend,” “project,” “estimate,” “anticipate,” “plan,” “believe,” or “continue” or similar terminology. Althou believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from our expectations include, but are not limited to, our assumptions about:

- the market prices of oil, natural gas, natural gas liquids (NGLs), and other products or services;
- our commodity hedging arrangements;
- the supply and demand for oil, natural gas, NGLs, and other products or services;
- production and reserve levels;
- drilling risks;
- economic and competitive conditions;
- the availability of capital resources;
- capital expenditure and other contractual obligations;
- currency exchange rates;
- weather conditions;
- inflation rates;
- the availability of goods and services;
- legislative, regulatory, or policy changes;
- terrorism or cyber attacks;
- occurrence of property acquisitions or divestitures;
- the integration of acquisitions;
- the securities or capital markets and related risks such as general credit, liquidity, market, and interest-rate risks; and
- other factors disclosed under Items 1 and 2—Business and Properties—Estimated Proved Reserves and Future Net Cash Flows, Item 1A—Risk Factors, Item 7—Management’s Discussion and Analysis of Financial Condition and Results of

Operations, Item 7A—Quantitative and Qualitative Disclosures About Market Risk and elsewhere in our most recently filed Annual Report on Form 10-K, other risks and uncertainties in our first-quarter 2018 earnings release, other factors disclosed under Part II, Item 1A—Risk Factors of this Quarterly Report on Form 10-Q, and other filings that we make with the Securities and Exchange Commission.

All subsequent written and oral forward-looking statements attributable to the Company, or persons acting on its behalf, are expressly qualified in their entirety by the cautionary statements. We assume no duty to update or revise our forward-looking statements based on changes in internal estimates or expectations or otherwise.

PART I – FINANCIAL INFORMATION
ITEM 1 – FINANCIAL STATEMENTS
APACHE CORPORATION AND SUBSIDIARIES
STATEMENT OF CONSOLIDATED OPERATIONS
(Unaudited)

	For the Quarter Ended March 31,	
	2018	2017
	(In millions, except per common share data)	
REVENUES AND OTHER:		
Oil and gas production revenues		
Oil revenues	$1,392	$1,172
Natural gas revenues	218	255
Natural gas liquids revenues	118	85
	1,728	1,512
Gain on divestitures	7	341
Other	7	25
	1,742	1,878
OPERATING EXPENSES:		
Lease operating expenses	349	336
Gathering, transmission, and processing	81	57
Taxes other than income	55	42
Exploration	76	92
General and administrative	114	103
Transaction, reorganization, and separation	—	(10)
Depreciation, depletion, and amortization:		
Oil and gas property and equipment	518	538
Other assets	35	38
Asset retirement obligation accretion	27	36
Impairments	—	8
Financing costs, net	99	100
	1,354	1,340
NET INCOME BEFORE INCOME TAXES	388	538
Current income tax provision	198	188
Deferred income tax provision (benefit)	(16)	83
NET INCOME INCLUDING NONCONTROLLING INTEREST	206	267
Net income attributable to noncontrolling interest	61	54
NET INCOME ATTRIBUTABLE TO COMMON STOCK	$145	$213
NET INCOME PER COMMON SHARE:		
Basic	$0.38	$0.56
Diluted	$0.38	$0.56
WEIGHTED-AVERAGE NUMBER OF COMMON SHARES OUTSTANDING:		
Basic	382	380
Diluted	384	383
DIVIDENDS DECLARED PER COMMON SHARE	$0.25	$0.25

The accompanying notes to consolidated financial statements are an integral part of this statement.

APACHE CORPORATION AND SUBSIDIARIES
STATEMENT OF CONSOLIDATED CASH FLOWS
(Unaudited)

	For the Three Months Ended March 31,	
	2018	2017
	(In millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income including noncontrolling interest	$206	$267
Adjustments to reconcile net income to net cash provided by operating activities:		
Unrealized derivative instrument gain, net	(49)	—
Gain on divestitures	(7)	(341)
Exploratory dry hole expense and unproved leasehold impairments	36	67
Depreciation, depletion, and amortization	553	576
Asset retirement obligation accretion	27	36
Impairments	—	8
Deferred income tax provision (benefit)	(16)	83
Other	49	34
Changes in operating assets and liabilities:		
Receivables	(65)	(41)
Inventories	(33)	12
Drilling advances	(41)	(12)
Deferred charges and other	32	(10)
Accounts payable	66	(56)
Accrued expenses	(149)	(175)
Deferred credits and noncurrent liabilities	6	7
NET CASH PROVIDED BY OPERATING ACTIVITIES	615	455
CASH FLOWS FROM INVESTING ACTIVITIES:		
Additions to oil and gas property	(737)	(322)
Leasehold and property acquisitions	(12)	(49)
Additions to gas gathering, transmission, and processing facilities	(128)	(142)
Proceeds from sale of oil and gas properties	9	426
Other, net	(22)	(6)
NET CASH USED IN INVESTING ACTIVITIES	(890)	(93)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Payments on fixed-rate debt	(150)	(70)
Distributions to noncontrolling interest	(69)	(57)
Dividends paid	(95)	(95)
Other	(2)	4
NET CASH USED IN FINANCING ACTIVITIES	(316)	(218)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(591)	144
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	1,668	1,377
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$1,077	$1,521
SUPPLEMENTARY CASH FLOW DATA:		

Interest paid, net of capitalized interest	$140	$140
Income taxes paid, net of refunds	191	65

The accompanying notes to consolidated financial statements
are an integral part of this statement.

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APACHE CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEET
(Unaudited)

	March 31, 2018	December 31, 2017
	(In millions)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$1,077	$ 1,668
Receivables, net of allowance	1,409	1,345
Inventories	386	368
Drilling advances	247	207
Prepaid assets and other	134	137
	3,253	3,725
PROPERTY AND EQUIPMENT:		
Oil and gas, on the basis of successful efforts accounting:		
Proved properties	39,958	39,197
Unproved properties and properties under development	1,773	1,783
Gathering, transmission and processing facilities	1,495	1,376
Other	1,056	1,046
	44,282	43,402
Less: Accumulated depreciation, depletion, and amortization	(26,196)	(25,643)
	18,086	17,759
OTHER ASSETS:		
Deferred charges and other	452	438
	$21,791	$ 21,922
LIABILITIES AND SHAREHOLDERS’ EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$708	$ 641
Current debt	400	550
Other current liabilities (Note 5)	1,234	1,373
	2,342	2,564
LONG-TERM DEBT	7,936	7,934
DEFERRED CREDITS AND OTHER NONCURRENT LIABILITIES:		
Income taxes	528	545
Asset retirement obligation	1,819	1,792
Other	297	296
	2,644	2,633
COMMITMENTS AND CONTINGENCIES (Note 9)		
EQUITY:		
Common stock, $0.625 par, 860,000,000 shares authorized, 415,315,787 and 414,125,879 shares issued, respectively	259	259
Paid-in capital	12,069	12,128
Accumulated deficit	(1,943)	(2,088)
Treasury stock, at cost, 33,169,135 and 33,171,015 shares, respectively	(2,887)	(2,887)
Accumulated other comprehensive income	4	4
APACHE SHAREHOLDERS’ EQUITY	7,502	7,416
Noncontrolling interest	1,367	1,375
TOTAL EQUITY	8,869	8,791

	$21,791	$ 21,922

The accompanying notes to consolidated financial statements
are an integral part of this statement.

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APACHE CORPORATION AND SUBSIDIARIES
STATEMENT OF CONSOLIDATED CHANGES IN EQUITY
(Unaudited)

	Common Stock	Paid-In Capital	Accumulated Deficit	Treasury Stock	Accumulated Other Comprehensive Income (Loss)	APACHE SHAREHOLDERS' EQUITY	Noncontrolling Interest	TOTAL EQUITY
	(In millions)							
BALANCE AT DECEMBER 31, 2016	$258	$12,364	$(3,385)	$(2,887)	$(112)	$6,238	$1,441	$7,679
Net income	—	—	213	—	—	213	54	267
Distributions to noncontrolling interest	—	—	—	—	—	—	(57)	(57)
Common dividends ($0.25 per share)	—	(95)	—	—	—	(95)	—	(95)
Other	—	36	(7)	—	—	29	—	29
BALANCE AT MARCH 31, 2017	$258	$12,305	$(3,179)	$(2,887)	$(112)	$6,385	$1,438	$7,823
BALANCE AT DECEMBER 31, 2017	$259	$12,128	$(2,088)	$(2,887)	$4	$7,416	$1,375	$8,791
Net income	—	—	145	—	—	145	61	206
Distributions to noncontrolling interest	—	—	—	—	—	—	(69)	(69)
Common dividends ($0.25 per share)	—	(96)	—	—	—	(96)	—	(96)
Other	—	37	—	—	—	37	—	37
BALANCE AT MARCH 31, 2018	$259	$12,069	$(1,943)	$(2,887)	$4	$7,502	$1,367	$8,869

The accompanying notes to consolidated financial statements are an integral part of this statement.

APACHE CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

These consolidated financial statements have been prepared by Apache Corporation (Apache or the Company) without audit, pursuant to the rules and regulations of the Securities and Exchange Commission (SEC). They reflect all adjustments that are, in the opinion of management, necessary for a fair presentation of the results for the interim periods, on a basis consistent with the annual audited financial statements, with the exception of recently adopted accounting pronouncements discussed below. All such adjustments are of a normal recurring nature. Certain information, accounting policies, and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States (GAAP) have been omitted pursuant to such rules and regulations, although the Company believes that the disclosures are adequate to make the information presented not misleading. This Quarterly Report on Form 10-Q should be read along with Apache's Annual Report on Form 10-K for the fiscal year ended December 31, 2017, which contains a summary of the Company's significant accounting policies and other disclosures.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

As of March 31, 2018, Apache's significant accounting policies are consistent with those discussed in Note 1—Summary of Significant Accounting Policies of its consolidated financial statements contained in Apache's Annual Report on Form 10-K for the fiscal year ended December 31, 2017, with the exception of Accounting Standards Update (ASU) 2014-09, "Revenue from Contracts with Customers (Topic 606)" (see "Revenue Recognition" section in this Note 1 below).

Use of Estimates

Preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates with regard to these financial statements include the fair value determination of acquired assets and liabilities, the estimate of proved oil and gas reserves and related present value estimates of future net cash flows therefrom, the assessment of asset retirement obligations, the estimates of fair value for long-lived assets, and the estimate of income taxes. Actual results could differ from those estimates.

Fair Value Measurements

Certain assets and liabilities are reported at fair value on a recurring basis in Apache's consolidated balance sheet. Accounting Standards Codification (ASC) 820-10-35, "Fair Value Measurement" (ASC 820), provides a hierarchy that prioritizes and defines the types of inputs used to measure fair value. The fair value hierarchy gives the highest priority to Level 1 inputs, which consist of unadjusted quoted prices for identical instruments in active markets. Level 2 inputs consist of quoted prices for similar instruments. Level 3 valuations are derived from inputs that are significant and unobservable; hence, these valuations have the lowest priority.

The valuation techniques that may be used to measure fair value include a market approach, an income approach, and a cost approach. A market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. An income approach uses valuation techniques to convert future amounts to a single present amount based on current market expectations, including present value techniques, option-pricing models, and the excess earnings method. The cost approach is based on the amount that currently would be required to replace the service capacity of an asset (replacement cost).

Recurring fair value measurements are presented in further detail in Note 4—Derivative Instruments and Hedging Activities and Note 8—Debt and Financing Costs.

Apache also uses fair value measurements on a nonrecurring basis when certain qualitative assessments of its assets indicate a potential impairment. The Company recorded no asset impairments in connection with fair value assessments in the first quarter of 2018. For the first quarter of 2017, the Company recorded asset impairments in connection with fair value assessments totaling $8 million for a United Kingdom (U.K.) Petroleum Revenue Tax (PRT) decommissioning asset that is no longer expected to be realizable from future abandonment activities in the North Sea.

In 2016, the U.K. government enacted Finance Bill 2016, providing tax relief to exploration and production (E&P) companies operating in the U.K. North Sea. Under the enacted legislation, the U.K. PRT rate was reduced to zero from the previously enacted 35 percent rate in effect from January 1, 2016. PRT expense ceased prospectively from that date. During the first quarter of 2017, the Company fully impaired the aggregate remaining value of the recoverable PRT decommissioning asset of $8 million that would have been realized from future abandonment activities. The recoverable value of the PRT decommissioning asset was estimated using the income approach. The expected future cash flows used in the determination were based on anticipated spending and timing of planned future abandonment activities for applicable fields, considering all available information at the date of review. Apache has classified this fair value measurement as Level 3 in the fair value hierarchy.

Oil and Gas Property

The Company follows the successful efforts method of accounting for its oil and gas property. Under this method of accounting, exploration costs such as exploratory geological and geophysical costs, delay rentals, and exploration overhead are expensed as incurred. All costs related to production, general corporate overhead, and similar activities are expensed as incurred. If an exploratory well provides evidence to justify potential development of reserves, drilling costs associated with the well are initially capitalized, or suspended, pending a determination as to whether a commercially sufficient quantity of proved reserves can be attributed to the area as a result of drilling. This determination may take longer than one year in certain areas depending on, among other things, the amount of hydrocarbons discovered, the outcome of planned geological and engineering studies, the need for additional appraisal drilling activities to determine whether the discovery is sufficient to support an economic development plan, and government sanctioning of development activities in certain international locations. At the end of each quarter, management reviews the status of all suspended exploratory well costs in light of ongoing exploration activities; in particular, whether the Company is making sufficient progress in its ongoing exploration and appraisal efforts or, in the case of discoveries requiring government sanctioning, whether development negotiations are underway and proceeding as planned. If management determines that future appraisal drilling or development activities are unlikely to occur, associated suspended exploratory well costs are expensed.

Acquisition costs of unproved properties are assessed for impairment at least annually and are transferred to proved oil and gas properties to the extent the costs are associated with successful exploration activities. Significant undeveloped leases are assessed individually for impairment based on the Company’s current exploration plans. Unproved oil and gas properties with individually insignificant lease acquisition costs are amortized on a group basis over the average lease term at rates that provide for full amortization of unsuccessful leases upon lease expiration or abandonment. Costs of expired or abandoned leases are charged to exploration expense, while costs of productive leases are transferred to proved oil and gas properties. Costs of maintaining and retaining unproved properties, as well as amortization of individually insignificant leases and impairment of unsuccessful leases, are included in exploration costs in the statement of consolidated operations.

Costs to develop proved reserves, including the costs of all development wells and related equipment used in the production of crude oil and natural gas, are capitalized. Depreciation of the cost of proved oil and gas properties is calculated using the unit-of-production (UOP) method. The UOP calculation multiplies the percentage of estimated proved reserves produced each quarter by the carrying value of those reserves. The reserve base used to calculate depreciation for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. The reserve base used to calculate the depreciation for capitalized costs for exploratory and development wells is the sum of proved developed reserves only. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are included in the depreciable cost.

Oil and gas properties are grouped for depreciation in accordance with ASC 932 “Extractive Activities—Oil and Gas.” The basis for grouping is a reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, such as a reservoir or field.

When circumstances indicate that proved oil and gas properties may be impaired, the Company compares unamortized capitalized costs to the expected undiscounted pre-tax future cash flows for the associated assets grouped at the lowest level for which identifiable cash flows are independent of cash flows of other assets. If the expected undiscounted pre-tax future cash flows, based on Apache’s estimate of future crude oil and natural gas prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is generally estimated using the income approach described in ASC 820. If applicable, the Company utilizes prices and other relevant information generated by market transactions involving assets and liabilities that are identical or comparable to the item being measured as the basis for determining fair value. The expected future cash flows used for impairment reviews and related fair value calculations are typically based on judgmental assessments of future production volumes, commodity prices, operating costs, and capital investment plans, considering all available information at the date of review. These assumptions are applied to develop future cash flow projections that are then discounted to estimated fair value, using a discount rate believed to be consistent with those applied by market participants. Apache has classified these fair value measurements as Level 3 in the fair value hierarchy.

The following table represents non-cash impairments of the carrying value of the Company's proved and unproved property and equipment for the first quarters of 2018 and 2017:

	Quarter Ended March 31,	
	2018	2017
	(In millions)	
Oil and Gas Property:		
Proved	$ —	$ —
Unproved	16	15

On the statement of consolidated operations, unproved impairments are recorded in exploration expense, and proved impairments are recorded in impairments.

Gains and losses on significant divestitures are recognized in the statement of consolidated operations.

Revenue Recognition

On January 1, 2018, Apache adopted ASU 2014-09, "Revenue from Contracts with Customers (ASC 606)," using the modified retrospective method. The Company elected to evaluate all contracts at the date of initial application. While there was no impact to the opening balance of retained earnings as a result of the adoption, certain items previously netted in revenue are now recognized as "Gathering, transmission, and processing" in the Company's statement of consolidated operations. The amounts reclassified are immaterial to the financial statements, and prior comparative periods have not been restated and continue to be reported under the accounting standards in effect for those periods. Adoption of the new standard is not anticipated to have a material impact on the Company's net earnings on an ongoing basis.

The Company applies the provisions of ASC 606 for revenue recognition to contracts with customers. Sales of crude oil, natural gas, and natural gas liquids (NGLs) are included in revenue when production is sold to a customer in fulfillment of performance obligations under the terms of agreed contracts. Performance obligations primarily comprise delivery of oil, gas, or NGLs at a delivery point, as negotiated within each contract. Each barrel of oil, million Btu (MMBtu) of natural gas, or other unit of measure is separately identifiable and represents a distinct performance obligation to which the transaction price is allocated. Performance obligations are satisfied at a point in time once control of the product has been transferred to the customer. The Company considers a variety of facts and circumstances in assessing the point of control transfer, including but not limited to: whether the purchaser can direct the use of the hydrocarbons, the transfer of significant risks and rewards, the Company's right to payment, and transfer of legal title. In each case, the term between delivery and when payments are due is not significant.

Apache markets its own United States (U.S.) natural gas and crude oil production based on market-priced contracts. Typically, these contracts are adjusted for quality, transportation, and other market-reflective differentials. Since the Company's production may fluctuate as a result of operational issues, it is occasionally necessary to purchase third-party oil and gas to fulfill sales obligations and commitments. Sales proceeds related to third-party purchased oil and gas are determined to be revenue from a customer. Proceeds for these volumes, which offset the associated purchase costs, totaled $104 million for the period ending March 31, 2018. Proceeds and costs are both recorded as "Other" under "Revenues and Other" in the statement of consolidated operations.

Internationally, Apache sells its North Sea crude oil under contracts with a market-based index price. Natural gas from the North Sea Beryl field is processed through the SAGE gas plant. The gas is sold to a third party at the St. Fergus entry point of the national grid on a National Balancing Point index price basis. Apache's gas production in Egypt is sold primarily under an industry-pricing formula, a sliding scale based on Dated Brent crude oil with a minimum of $1.50 per MMBtu and a maximum of $2.65 per MMBtu, plus an upward adjustment for liquids content. The Company's Egypt oil production is sold at prices equivalent to the export market.

The Company's Egyptian operations are conducted pursuant to production sharing contracts under which contractor partners pay all operating and capital costs for exploring and developing the concessions. A percentage of the production, generally up to 40 percent, is available to contractor partners to recover these operating and capital costs over contractually defined periods. The balance of the production is split among the contractor partners and the Egyptian General Petroleum Corporation (EGPC) on a contractually defined basis. Additionally, the contractor partner's income taxes, which remain the liability of the contractor partners under domestic law, are paid by EGPC on behalf of the contractor partners out of EGPC's production entitlement. Income taxes paid to the Arab Republic of Egypt on behalf of Apache as contract partner are recognized as oil and gas sales revenue and income tax expense and reflected as production and estimated reserves. Revenues related to Egypt's tax volumes are considered revenue from a non-customer.

For the period ending March 31, 2018, revenues from customers and revenues from non-customers were $1.7 billion and $155 million, respectively.

Apache records trade accounts receivable for its unconditional rights to consideration arising under sales contracts with customers. The carrying value of such receivables, net of the allowance for doubtful accounts, represents estimated net realizable value. The Company routinely assesses the collectability of all material trade and other receivables. The Company accrues a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of any reserve may be reasonably estimated. Receivables from contracts with customers, net of allowance for doubtful accounts, totaled $1.2 billion and $1.1 billion as of March 31, 2018 and December 31, 2017, respectively.

Apache has concluded that disaggregating revenue by geographic area and by product appropriately depicts how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors. Refer to Note 11—Business Segment Information for a disaggregation of revenue by each product sold.

Practical Expedients and Exemptions

Apache does not disclose the value of unsatisfied performance obligations for contracts with an original expected length of one year or less or contracts for which variable consideration is allocated entirely to a wholly unsatisfied performance obligation.

Apache will utilize the practical expedient to expense incremental costs of obtaining a contract if the expected amortization period is one year or less. Costs to obtain a contract with expected amortization periods of greater than one year will be recorded as an asset and will be recognized in accordance with ASC 340, “Other Assets and Deferred Costs.” Currently, the Company does not have contract assets related to incremental costs to obtain a contract.

New Pronouncements Issued But Not Yet Adopted

In February 2016, the Financial Accounting Standards Board (FASB) issued ASU 2016-02, “Leases (Topic 842),” requiring lessees to recognize lease assets and lease liabilities for most leases classified as operating leases under previous GAAP. The guidance is effective for fiscal years beginning after December 15, 2018. Early adoption is permitted; however, the Company does not intend to early adopt. In January 2018, the FASB issued a proposed ASU update that would add a transition option permitting entities to apply the provisions of the new standard at its adoption date instead of the earliest comparative period presented in the consolidated financial statements. If finalized, comparative reporting would not be required and the provisions of the standard would be applied prospectively to leases in effect at the date of adoption. In the normal course of business, the Company enters into various lease agreements for real estate, aircraft, and equipment related to its exploration and development activities that are currently accounted for as operating leases. At this time, the Company cannot reasonably estimate the financial impact this will have on its consolidated financial statements; however, the Company believes adoption and implementation of this ASU will significantly impact its balance sheet, resulting in an increase in both assets and liabilities relating to its leasing activities. As part of the assessment to date, the Company has formed an implementation work team, developed a project plan, educated departments affected by the standard, and continues to evaluate contracts and monitor updates to the new standard to determine the impact this ASU will have on its consolidated financial statements.

2. ACQUISITIONS AND DIVESTITURES

2018 Activity

During the first quarter of 2018, Apache completed the sale of certain non-core assets, primarily in the Permian region, in multiple transactions for cash proceeds of $9 million. The Company recognized gains of approximately $7 million during the first quarter upon closing of these transactions.

Leasehold and Property Acquisitions

During the first quarter of 2018, Apache completed $12 million of leasehold and property acquisitions primarily in its U.S. onshore regions.

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2017 Activity

During the first quarter of 2017, Apache completed the sale of certain non-core assets, primarily in the Permian region, in multiple transactions for cash proceeds of $466 million, subject to customary closing adjustments. A refundable deposit of $40 million was received in the fourth quarter of 2016 in connection with these transactions. The Company recognized gains of approximately $341 million during the first quarter upon closing of these transactions.

Leasehold and Property Acquisitions

During the first quarter of 2017, Apache completed $49 million of leasehold and property acquisitions primarily in its U.S. onshore regions.

3. CAPITALIZED EXPLORATORY WELL COSTS

The Company’s capitalized exploratory well costs were $363 million and $350 million at March 31, 2018 and >

INCOME TAX EXPENSE (BENEFIT)

8,785 26,461 19,628 (35,045)

NET INCOME (LOSS)

21,922 47,724 35,918 (57,676)

Noncontrolling interest income

366 419 785 877

EARNINGS (LOSS) AVAILABLE TO PARENT

$21,556 $47,305 $35,133 $(58,553)

STATEMENTS OF COMPREHENSIVE INCOME

NET INCOME (LOSS)

$21,922 $47,724 $35,918 $(57,676)

OTHER COMPREHENSIVE INCOME (LOSS):

Pension and other postretirement benefits

	3,228	43,903	(19,357)	47,870
Income tax expense (benefit) related to other comprehensive income	976	17,936	(7,301)	19,306
Other comprehensive income (loss), net of tax	2,252	25,967	(12,056)	28,564
COMPREHENSIVE INCOME (LOSS)	24,174	73,691	23,862	(29,112)
COMPREHENSIVE INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	366	419	785	877
COMPREHENSIVE INCOME (LOSS) AVAILABLE TO PARENT	$23,808	$73,272	$23,077	$(29,989)

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

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THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2010	December 31, 2009
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 245	$ 86,230
Receivables-		
Customers (less accumulated provisions of $4,809,000 and $5,239,000, respectively, for uncollectible accounts)	198,970	209,335
Associated companies	73,008	98,954
Other	10,377	11,661
Notes receivable from associated companies	24,480	26,802
Prepayments and other	4,390	9,973
	311,470	442,955
UTILITY PLANT:		
In service	2,350,804	2,310,074
Less Accumulated provision for depreciation	911,368	888,169
	1,439,436	1,421,905
Construction work in progress	30,665	36,907
	1,470,101	1,458,812
OTHER PROPERTY AND INVESTMENTS:		
Investment in lessor notes	340,033	388,641
Other	10,108	10,220
	350,141	398,861
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	1,688,521	1,688,521
Regulatory assets	468,119	545,505
Pension assets (Note 5)		13,380
Property taxes	77,319	77,319
Other	12,912	12,777
	2,246,872	2,337,502
	$ 4,378,584	$ 4,638,130

LIABILITIES AND CAPITALIZATION

CURRENT LIABILITIES:		
Currently payable long-term debt	$ 137	$ 117
Short-term borrowings-		
Associated companies	224,031	339,728
Accounts payable-		
Associated companies	35,605	68,634
Other	15,707	17,166
Accrued taxes	77,051	90,511
Accrued interest	18,557	18,466
Other	49,897	45,440
	420,985	580,062
CAPITALIZATION:		
Common stockholders equity-		
Common stock, without par value, authorized 105,000,000 shares, 67,930,743 shares outstanding	884,878	884,897
Accumulated other comprehensive loss	(150,214)	(138,158)
Retained earnings	532,380	597,248
Total common stockholders equity	1,267,044	1,343,987
Noncontrolling interest	18,017	20,592
Total equity	1,285,061	1,364,579
Long-term debt and other long-term obligations	1,852,488	1,872,750
	3,137,549	3,237,329
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	632,696	644,745
Accumulated deferred investment tax credits	11,415	11,836
Retirement benefits	81,872	69,733
Other	94,067	94,425
	820,050	820,739
COMMITMENTS AND CONTINGENCIES (Note 8)		
	$ 4,378,584	$ 4,638,130

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

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

	Six Months Ended June 30	
	2010	**2009**
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income (Loss)	$ 35,918	$ (57,676)
Adjustments to reconcile net income (loss) to net cash from operating activities-		
Provision for depreciation	36,447	36,132
Amortization of regulatory assets, net	75,946	286,317
Deferral of new regulatory assets		(134,587)
Purchased power cost recovery reconciliation		2,072
Deferred income taxes and investment tax credits, net	(18,083)	(58,506)
Accrued compensation and retirement benefits	5,421	2,092
Accrued regulatory obligations	(444)	12,057
Electric service prepayment programs		(3,510)
Cash collateral from suppliers	685	5,365
Decrease (increase) in operating assets-		
Receivables	51,757	(84,469)
Prepayments and other current assets	5,392	(1,145)
Increase (decrease) in operating liabilities-		
Accounts payable	(34,488)	18,991
Accrued taxes	(11,317)	(29,434)
Accrued interest	91	232
Other	1,932	3,265
Net cash provided from (used for) operating activities	149,257	(2,804)
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Short-term borrowings, net		47,423
Redemptions and Repayments-		
Long-term debt	(54)	(368)
Short-term borrowings, net	(136,013)	
Common stock dividend payments	(100,000)	(25,000)
Other	(3,367)	(3,019)
Net cash provided from (used for) financing activities	(239,434)	19,036
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(44,373)	(46,434)
Loan repayments from (loans to) associated companies, net	2,322	(5,449)
Redemptions of lessor notes	48,608	37,070
Other	(2,365)	(1,415)

Net cash provided from (used for) investing activities		4,192		(16,228)
Net change in cash and cash equivalents		(85,985)		4
Cash and cash equivalents at beginning of period		86,230		226
Cash and cash equivalents at end of period	$	245	$	230

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

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

	Three Months Ended June 30		Six Months Ended June 30	
	2010	2009	2010	2009
	(In thousands)			
STATEMENTS OF INCOME				
REVENUES:				
Electric sales	$ 114,691	$ 219,911	$ 240,122	$ 456,996
Excise tax collections	6,059	6,297	13,100	14,026
Total revenues	120,750	226,208	253,222	471,022
EXPENSES:				
Purchased power from affiliates	38,654	130,564	85,654	255,888
Purchased power from non-affiliates	23,675	18,244	49,784	58,781
Other operating expenses	25,499	35,480	51,044	80,484
Provision for depreciation	8,013	7,717	15,963	15,289
Amortization (deferral) of regulatory assets, net	(1,800)	11,771	(10,299)	21,668
General taxes	12,282	12,349	25,743	26,599
Total expenses	106,323	216,125	217,889	458,709
OPERATING INCOME	14,427	10,083	35,333	12,313
OTHER INCOME (EXPENSE):				
Investment income	5,057	7,529	8,857	13,013
Miscellaneous income (expense)	(945)	1,375	(2,351)	35
Interest expense	(10,455)	(9,262)	(20,942)	(14,795)
Capitalized interest	80	50	158	92
Total other expense	(6,263)	(308)	(14,278)	(1,655)
INCOME BEFORE INCOME TAXES	8,164	9,775	21,055	10,658
INCOME TAXES	948	3,370	6,330	3,261
NET INCOME	7,216	6,405	14,725	7,397
Noncontrolling interest income	2	1	5	3

EARNINGS AVAILABLE TO PARENT	$	7,214	$	6,404	$	14,720	$	7,394

STATEMENTS OF COMPREHENSIVE INCOME

NET INCOME	$	7,216	$	6,405	$	14,725	$	7,397
OTHER COMPREHENSIVE INCOME (LOSS):								
Pension and other postretirement benefits		714		19,016		1,010		19,149
Change in unrealized gain on available-for-sale securities		(330)		(2,739)		39		(3,548)
Other comprehensive income		384		16,277		1,049		15,601
Income tax expense related to other comprehensive income		65		7,224		235		7,205
Other comprehensive income, net of tax		319		9,053		814		8,396
COMPREHENSIVE INCOME		7,535		15,458		15,539		15,793
COMPREHENSIVE INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST		2		1		5		3
COMPREHENSIVE INCOME AVAILABLE TO PARENT	$	7,533	$	15,457	$	15,534	$	15,790

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

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THE TOLEDO EDISON COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2010	December 31, 2009
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 77,843	$ 436,712
Receivables-		
Customers	128	75
Associated companies	52,068	90,191
Other (less accumulated provisions of $298,000 and $208,000, respectively, for uncollectible accounts)	18,866	20,180
Notes receivable from associated companies	95,919	85,101
Prepayments and other	3,503	7,111
	248,327	639,370
UTILITY PLANT:		
In service	932,788	912,930
Less Accumulated provision for depreciation	437,327	427,376
	495,461	485,554
Construction work in progress	7,906	9,069
	503,367	494,623
OTHER PROPERTY AND INVESTMENTS:		
Investment in lessor notes	103,872	124,357
Nuclear plant decommissioning trusts	75,540	73,935
Other	1,539	1,580
	180,951	199,872
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	500,576	500,576
Regulatory assets	81,799	69,557
Property taxes	23,658	23,658
Other	38,655	55,622
	644,688	649,413
	$ 1,577,333	$ 1,983,278

LIABILITIES AND CAPITALIZATION

CURRENT LIABILITIES:		
Currently payable long-term debt	$ 216	$ 222
Accounts payable-		
Associated companies	16,535	78,341
Other	6,972	8,312
Notes payable to associated companies		225,975
Accrued taxes	20,069	25,734
Lease market valuation liability	36,900	36,900
Other	22,244	29,273
	102,936	404,757
CAPITALIZATION:		
Common stockholders equity-		
Common stock, $5 par value, authorized 60,000,000 shares, 29,402,054 shares outstanding	147,010	147,010
Other paid-in-capital	178,136	178,181
Accumulated other comprehensive loss	(48,989)	(49,803)
Retained earnings	99,210	214,490
Total common stockholders equity	375,367	489,878
Noncontrolling interest	2,590	2,696
Total equity	377,957	492,574
Long-term debt and other long-term obligations	600,463	600,443
	978,420	1,093,017
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	112,670	80,508
Accumulated deferred investment tax credits	6,148	6,367
Retirement benefits	67,507	65,988
Asset retirement obligations	27,819	32,290
Lease market valuation liability	217,750	236,200
Other	64,083	64,151
	495,977	485,504
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 8)		
	$ 1,577,333	$ 1,983,278

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

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

	Six Months Ended June 30	
	2010	**2009**
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$ 14,725	$ 7,397
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	15,963	15,289
Amortization (deferral) of regulatory assets, net	(10,299)	21,668
Purchased power cost recovery reconciliation	60	(4,197)
Deferred rents and lease market valuation liability	(42,264)	(40,697)
Deferred income taxes and investment tax credits, net	16,503	(1,206)
Accrued compensation and retirement benefits	2,600	711
Accrued regulatory obligations	(632)	4,450
Electric service prepayment programs		(1,458)
Cash collateral from suppliers	343	2,755
Decrease (increase) in operating assets-		
Receivables	52,754	1,075
Prepayments and other current assets	3,608	(220)
Increase (decrease) in operating liabilities-		
Accounts payable	(61,195)	5,533
Accrued taxes	(4,007)	(2,936)
Accrued interest		3,983
Other	(9,020)	1,788
Net cash provided from (used for) operating activities	(20,861)	13,935
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt		297,422
Short-term borrowings, net		59,938
Redemptions and Repayments-		
Long-term debt	(111)	(236)
Short-term borrowings, net	(225,975)	
Common stock dividend payments	(130,000)	(25,000)
Other	(112)	(247)
Net cash provided from (used for) financing activities	(356,198)	331,877
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(20,237)	(21,661)
Leasehold improvement payments from associated companies	32,829	
Loans to associated companies, net	(10,818)	(19,819)

Redemptions of lessor notes	20,485	18,330
Sales of investment securities held in trusts	106,814	77,323
Purchases of investment securities held in trusts	(107,978)	(78,700)
Other	(2,905)	(1,845)
Net cash provided from (used for) investing activities	18,190	(26,372)
Net change in cash and cash equivalents	(358,869)	319,440
Cash and cash equivalents at beginning of period	436,712	14
Cash and cash equivalents at end of period	$ 77,843	$ 319,454

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

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

	Three Months Ended June 30		Six Months Ended June 30	
	2010	2009	2010	2009
	(In thousands)			
REVENUES:				
Electric sales	$ 709,606	$ 697,061	$ 1,400,998	$ 1,457,981
Excise tax collections	11,012	11,031	23,364	23,762
Total revenues	720,618	708,092	1,424,362	1,481,743
EXPENSES:				
Purchased power	410,470	423,950	824,486	905,191
Other operating expenses	75,177	70,876	170,837	156,746
Provision for depreciation	27,093	25,301	55,064	50,404
Amortization of regulatory assets, net	81,326	80,018	150,774	166,849
General taxes	14,902	12,587	31,338	30,083
Total expenses	608,968	612,732	1,232,499	1,309,273
OPERATING INCOME	111,650	95,360	191,863	172,470
OTHER INCOME (EXPENSE):				
Miscellaneous income	1,649	2,007	3,482	2,812
Interest expense	(30,041)	(29,671)	(59,464)	(57,539)
Capitalized interest	156	218	289	280
Total other expense	(28,236)	(27,446)	(55,693)	(54,447)
INCOME BEFORE INCOME TAXES	83,414	67,914	136,170	118,023
INCOME TAXES	33,521	29,848	57,051	52,399
NET INCOME	49,893	38,066	79,119	65,624
OTHER COMPREHENSIVE INCOME:				
Pension and other postretirement benefits	4,135	20,918	20,063	25,039
Unrealized gain on derivative hedges	69	69	138	138
Other comprehensive income	4,204	20,987	20,201	25,177

Income tax expense related to other comprehensive income		1,441		11,059		7,999		12,489
Other comprehensive income, net of tax		2,763		9,928		12,202		12,688
TOTAL COMPREHENSIVE INCOME	$	52,656	$	47,994	$	91,321	$	78,312

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

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

	June 30, 2010	December 31, 2009
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 99	$ 27
Receivables-		
Customers (less accumulated provisions of $3,362,000 and $3,506,000, respectively, for uncollectible accounts)	345,136	300,991
Associated companies	11,778	12,884
Other	25,626	21,877
Notes receivable associated companies	17,883	102,932
Prepaid taxes	146,898	34,930
Other	11,357	12,945
	558,777	486,586
UTILITY PLANT:		
In service	4,524,706	4,463,490
Less Accumulated provision for depreciation	1,651,304	1,617,639
	2,873,402	2,845,851
Construction work in progress	55,825	54,251
	2,929,227	2,900,102
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	166,148	166,768
Nuclear fuel disposal trust	204,088	199,677
Other	2,209	2,149
	372,445	368,594
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	1,810,936	1,810,936
Regulatory assets	800,898	888,143
Other	29,849	27,096
	2,641,683	2,726,175
	$ 6,502,132	$ 6,481,457

LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 31,508	$ 30,639
Short-term borrowings-		
Associated companies	57,850	
Accounts payable-		
Associated companies	15,158	26,882
Other	202,049	168,093
Accrued taxes	1,786	12,594
Accrued interest	18,189	18,256
Other	82,524	111,156
	409,064	367,620
CAPITALIZATION:		
Common stockholders equity-		
Common stock, $10 par value, authorized 16,000,000 shares, 13,628,447 shares outstanding	136,284	136,284
Other paid-in capital	2,507,003	2,507,049
Accumulated other comprehensive loss	(230,810)	(243,012)
Retained earnings	189,194	200,075
Total common stockholders equity	2,601,671	2,600,396
Long-term debt and other long-term obligations	1,787,235	1,801,589
	4,388,906	4,401,985
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	705,219	687,545
Nuclear fuel disposal costs	196,623	196,511
Retirement benefits	132,565	150,603
Asset retirement obligations	104,878	101,568
Power purchase contract liability	378,448	399,105
Other	186,429	176,520
	1,704,162	1,711,852
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 8)		
	$ 6,502,132	$ 6,481,457

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

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

	Six Months Ended June 30	
	2010	**2009**
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$ 79,119	$ 65,624
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	55,064	50,404
Amortization of regulatory assets, net	150,774	166,849
Deferred purchased power and other costs	(67,664)	(50,542)
Deferred income taxes and investment tax credits, net	(1,425)	3,440
Accrued compensation and retirement benefits	2,608	(2,883)
Cash collateral paid, net	(23,400)	(209)
Decrease (increase) in operating assets-		
Receivables	(46,788)	41,228
Prepayments and other current assets	(112,155)	(145,740)
Increase (decrease) in operating liabilities-		
Accounts payable	11,924	(19,321)
Accrued taxes	10,368	(14,007)
Accrued interest	(67)	9,373
Tax collections payable		(9,714)
Other	(6,192)	4,555
Net cash provided from operating activities	52,166	99,057
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt		299,619
Short-term borrowings, net	57,850	
Redemptions and Repayments-		
Common stock		(150,000)
Long-term debt	(13,830)	(13,093)
Short-term borrowings, net		(56,267)
Common stock dividend payments	(90,000)	(88,000)
Other		(2,260)
Net cash used for financing activities	(45,980)	(10,001)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(80,727)	(78,401)
Loan repayments from (loans to) associated companies, net	85,049	(1,341)
Sales of investment securities held in trusts	281,242	244,880
Purchases of investment securities held in trusts	(289,454)	(252,856)

Other		(2,224)		(1,266)
Net cash used for investing activities		(6,114)		(88,984)
Net change in cash and cash equivalents		72		72
Cash and cash equivalents at beginning of period		27		66
Cash and cash equivalents at end of period	$	99	$	138

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

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

	Three Months Ended June 30		Six Months Ended June 30	
	2010	**2009**	**2010**	**2009**
	(In thousands)			
REVENUES:				
Electric sales	$ 422,030	$ 360,022	$ 873,590	$ 769,708
Gross receipts tax collections	20,629	17,586	42,196	37,569
Total revenues	442,659	377,608	915,786	807,277
EXPENSES:				
Purchased power from affiliates	149,000	78,652	310,080	178,729
Purchased power from non-affiliates	85,276	123,299	177,204	247,210
Other operating expenses	90,151	51,309	192,134	157,666
Provision for depreciation	13,440	12,919	26,198	25,058
Amortization of regulatory assets, net	48,589	61,548	97,389	89,139
General taxes	19,894	22,034	41,634	43,969
Total expenses	406,350	349,761	844,639	741,771
OPERATING INCOME	36,309	27,847	71,147	65,506
OTHER INCOME (EXPENSE):				
Interest income	880	2,769	2,097	5,955
Miscellaneous income	1,381	1,058	3,554	1,914
Interest expense	(13,002)	(14,763)	(26,775)	(28,122)
Capitalized interest	159	62	285	77
Total other expense	(10,582)	(10,874)	(20,839)	(20,176)
INCOME BEFORE INCOME TAXES	25,727	16,973	50,308	45,330
INCOME TAXES	8,618	6,968	20,884	18,703
NET INCOME	17,109	10,005	29,424	26,627
OTHER COMPREHENSIVE INCOME:				
Pension and other postretirement benefits	2,162	27,369	11,871	31,922
Unrealized gain on derivative hedges	84	84	168	168

Other comprehensive income	2,246	27,453	12,039	32,090
Income tax expense related to other comprehensive income	724	13,592	4,901	15,385
Other comprehensive income, net of tax	1,522	13,861	7,138	16,705
TOTAL COMPREHENSIVE INCOME	$ 18,631	$ 23,866	$ 36,562	$ 43,332

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

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METROPOLITAN EDISON COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2010	December 31, 2009
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 126	$ 120
Receivables-		
Customers (less accumulated provisions of $3,877,000 and $4,044,000, respectively, for uncollectible accounts)	188,771	171,052
Associated companies	45,551	29,413
Other	13,221	11,650
Notes receivable from associated companies	11,207	97,150
Prepaid taxes	46,475	15,229
Other	649	1,459
	306,000	326,073
UTILITY PLANT:		
In service	2,196,713	2,162,815
Less Accumulated provision for depreciation	830,042	810,746
	1,366,671	1,352,069
Construction work in progress	30,214	14,901
	1,396,885	1,366,970
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	263,752	266,479
Other	881	890
	264,633	267,369
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	416,499	416,499
Regulatory assets	385,392	356,754
Power purchase contract asset	120,436	176,111
Other	42,546	36,544
	964,873	985,908
	$ 2,932,391	$ 2,946,320

LIABILITIES AND CAPITALIZATION

CURRENT LIABILITIES:

Currently payable long-term debt	$ 28,500	$ 128,500
Short-term borrowings-		
Associated companies	17,898	
Accounts payable-		
Associated companies	51,308	40,521
Other	30,997	41,050
Accrued taxes	20,689	11,170
Accrued interest	16,085	17,362
Other	28,588	24,520
	194,065	263,123
CAPITALIZATION:		
Common stockholders equity-		
Common stock, without par value, authorized 900,000 shares, 859,500 shares outstanding	1,197,014	1,197,070
Accumulated other comprehensive loss	(136,413)	(143,551)
Retained earnings	33,824	4,399
Total common stockholders equity	1,094,425	1,057,918
Long-term debt and other long-term obligations	713,920	713,873
	1,808,345	1,771,791
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	454,777	453,462
Accumulated deferred investment tax credits	7,090	7,313
Nuclear fuel disposal costs	44,416	44,391
Retirement benefits	29,194	33,605
Asset retirement obligations	186,373	180,297
Power purchase contract liability	158,987	143,135
Other	49,144	49,203
	929,981	911,406
COMMITMENTS AND CONTINGENCIES (Note 8)		
	$ 2,932,391	$ 2,946,320

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

METROPOLITAN EDISON COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30 2010	Six Months Ended June 30 2009
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$ 29,424	$ 26,627
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	26,198	25,058
Amortization of regulatory assets, net	97,389	89,139
Deferral of regulatory assets	(38,358)	(47,592)
Deferred income taxes and investment tax credits, net	(12,079)	30,135
Accrued compensation and retirement benefits	(1,573)	3,250
Cash collateral received (paid), net	50	(6,800)
Decrease (increase) in operating assets-		
Receivables	(29,439)	346
Prepayments and other current assets	(30,436)	(39,068)
Increase (decrease) in operating liabilities-		
Accounts payable	733	(18,624)
Accrued taxes	9,519	(1,754)
Accrued interest	(1,277)	10,230
Other	6,743	7,870
Net cash provided from operating activities	56,894	78,817
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt		300,000
Short-term borrowings, net	17,898	
Redemptions and Repayments-		
Long-term debt	(100,000)	
Short-term borrowings, net		(15,003)
Other		(2,267)
Net cash provided from (used for) financing activities	(82,102)	282,730
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(54,405)	(48,464)
Sales of investment securities held in trusts	376,610	63,086
Purchases of investment securities held in trusts	(381,219)	(67,668)
Loans from (to) associated companies, net	85,943	(306,448)
Other	(1,715)	(2,072)
Net cash provided from (used for) investing activities	25,214	(361,566)

Net change in cash and cash equivalents		6		(19)
Cash and cash equivalents at beginning of period		120		144
Cash and cash equivalents at end of period	$	126	$	125

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

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

	Three Months Ended June 30		Six Months Ended June 30	
	2010	**2009**	**2010**	**2009**
	(In thousands)			
REVENUES:				
Electric sales	$ 350,335	$ 316,881	$ 736,271	$ 688,174
Gross receipts tax collections	16,162	14,804	33,686	32,096
Total revenues	366,497	331,685	769,957	720,270
EXPENSES:				
Purchased power from affiliates	152,945	72,166	321,345	168,247
Purchased power from non-affiliates	86,829	125,317	178,252	252,483
Other operating expenses	67,070	46,301	139,464	123,590
Provision for depreciation	16,605	15,581	31,287	30,036
Amortization (deferral) of regulatory assets, net	(10,522)	18,113	(20,488)	26,889
General taxes	18,647	18,251	35,181	38,844
Total expenses	331,574	295,729	685,041	640,089
OPERATING INCOME	34,923	35,956	84,916	80,181
OTHER INCOME (EXPENSE):				
Miscellaneous income	1,310	911	2,923	1,709
Interest expense	(17,630)	(11,843)	(34,920)	(25,076)
Capitalized interest	183	29	323	51
Total other expense	(16,137)	(10,903)	(31,674)	(23,316)
INCOME BEFORE INCOME TAXES	18,786	25,053	53,242	56,865
INCOME TAXES	5,812	10,232	22,969	23,354
NET INCOME	12,974	14,821	30,273	33,511
OTHER COMPREHENSIVE INCOME:				
Pension and other postretirement benefits	1,830	29,400	10,377	32,355
Unrealized gain on derivative hedges	16	16	32	32
		6		(16)

Change in unrealized gain on available-for-sale securities								
Other comprehensive income		1,846		29,422		10,409		32,371
Income tax expense related to other comprehensive income		483		15,100		3,767		16,155
Other comprehensive income, net of tax		1,363		14,322		6,642		16,216
TOTAL COMPREHENSIVE INCOME	$	14,337	$	29,143	$	36,915	$	49,727

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

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PENNSYLVANIA ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2010	December 31, 2009
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 10	$ 14
Receivables-		
Customers (less accumulated provisions of $3,428,000 and $3,483,000, respectively, for uncollectible accounts)	137,450	139,302
Associated companies	88,612	77,338
Other	10,934	18,320
Notes receivable from associated companies	14,092	14,589
Prepaid taxes	56,450	18,946
Other	758	1,400
	308,306	269,909
UTILITY PLANT:		
In service	2,481,942	2,431,737
Less Accumulated provision for depreciation	918,963	901,990
	1,562,979	1,529,747
Construction work in progress	22,319	24,205
	1,585,298	1,553,952
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	140,611	142,603
Non-utility generation trusts	96,988	120,070
Other	283	289
	237,882	262,962
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	768,628	768,628
Regulatory assets	138,557	9,045
Power purchase contract asset	6,031	15,362
Other	20,245	19,143
	933,461	812,178
	$ 3,064,947	$ 2,899,001
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		

Currently payable long-term debt	$ 69,310	$ 69,310
Short-term borrowings-		
Associated companies	66,786	41,473
Accounts payable-		
Associated companies	48,876	39,884
Other	28,460	41,990
Accrued taxes	5,071	6,409
Accrued interest	17,625	17,598
Other	24,696	22,741
	260,824	239,405
CAPITALIZATION:		
Common stockholders equity-		
Common stock, $20 par value, authorized 5,400,000 shares, 4,427,577 shares outstanding	88,552	88,552
Other paid-in capital	913,460	913,437
Accumulated other comprehensive loss	(155,462)	(162,104)
Retained earnings	121,774	91,501
Total common stockholders equity	968,324	931,386
Long-term debt and other long-term obligations	1,072,199	1,072,181
	2,040,523	2,003,567
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	296,829	242,040
Retirement benefits	167,288	174,306
Asset retirement obligations	94,933	91,841
Power purchase contract liability	153,603	100,849
Other	50,947	46,993
	763,600	656,029
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 8)		
	$ 3,064,947	$ 2,899,001

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

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PENNSYLVANIA ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30 2010	Six Months Ended June 30 2009
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$ 30,273	$ 33,511
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	31,287	30,036
Amortization (deferral) of regulatory assets, net	(20,488)	26,889
Deferred costs recoverable as regulatory assets	(38,955)	(46,349)
Deferred income taxes and investment tax credits, net	42,943	24,700
Accrued compensation and retirement benefits	4,216	490
Cash collateral	(3,613)	2
Decrease (increase) in operating assets-		
Receivables	3,266	42,494
Prepayments and other current assets	(36,864)	(35,750)
Increase (decrease) in operating liabilities-		
Accounts payable	(4,603)	(10,108)
Accrued taxes	(1,339)	(7,629)
Accrued interest	28	(1,669)
Other	9,559	2,302
Net cash provided from operating activities	15,710	58,919
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Short-term borrowings, net	25,313	146,654
Redemptions and Repayments-		
Long-term debt		(100,000)
Common stock dividend payments		(35,000)
Other	5	
Net cash provided from financing activities	25,318	11,654
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(58,293)	(59,606)
Loans from associated companies, net	498	63
Sales of investment securities held in trusts	133,934	53,504
Purchases of investment securities held in trusts	(113,067)	(60,378)
Other	(4,104)	(4,168)
Net cash used for investing activities	(41,032)	(70,585)

Net change in cash and cash equivalents		(4)		(12)
Cash and cash equivalents at beginning of period		14		23
Cash and cash equivalents at end of period	$	10	$	11

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

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, FES and its subsidiaries FGCO and NGC, and FESC.

FirstEnergy and its subsidiaries follow GAAP and comply with the regulations, orders, policies and practices prescribed by the SEC, the FERC and, as applicable, the PUCO, the PPUC and the NJBPU. 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. In preparing the financial statements, FirstEnergy and its subsidiaries have evaluated events and transactions for potential recognition or disclosure through the date the financial statements were issued.

These 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, 2009 for FirstEnergy, FES and the Utilities, as applicable. The consolidated unaudited financial statements of FirstEnergy, FES and each of the Utilities 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 6). Investments in affiliates over which FirstEnergy and its subsidiaries have the ability to exercise significant influence, but 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. EARNINGS PER SHARE

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

Reconciliation of Basic and Diluted Earnings per Share of Common Stock	**Three Months Ended June 30** 2010	2009	**Six Months Ended June 30** 2010	2009
	(In millions, except per share amounts)			
Earnings available to FirstEnergy Corp.	$ 265	$ 414	$ 420	$ 533
Weighted average number of basic shares outstanding	304	304	304	304
Assumed exercise of dilutive stock options and awards	1	1	1	2
Weighted average number of diluted shares outstanding	305	305	305	306
Basic earnings per share of common stock	$ 0.87	$ 1.36	$ 1.38	$ 1.75

Diluted earnings per share of common stock	$	0.87	$	1.36	$	1.37	$	1.75

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3. FAIR VALUE OF FINANCIAL INSTRUMENTS

(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 as of June 30, 2010 and December 31, 2009:

	June 30, 2010		December 31, 2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
FirstEnergy	$ 13,346	$ 14,992	$ 13,753	$ 14,502
FES	3,932	4,386	4,224	4,306
OE	1,166	1,378	1,169	1,299
CEI	1,853	2,110	1,873	2,032
TE	600	682	600	638
JCP&L	1,826	2,013	1,840	1,950
Met-Ed	742	840	842	909
Penelec	1,144	1,233	1,144	1,177

The fair values of long-term debt and other long-term obligations reflect the present value of the cash outflows relating to those securities based on the current call price, the yield to maturity or the yield to call, as deemed appropriate at the end of each respective period. The yields assumed were based on securities with similar characteristics offered by corporations with credit ratings similar to those of FES and the Utilities.

(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.

Available-For-Sale Securities

The following table summarizes the amortized cost basis, unrealized gains and losses and fair values of investments held in nuclear decommissioning trusts, nuclear fuel disposal trusts and NUG trusts as of June 30, 2010 and December 31, 2009:

	June 30, 2010[1]				December 31, 2009[2]			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
	(In millions)							
Debt securities								
FirstEnergy	$ 1,404	$ 40	$	$ 1,444	$ 1,727	$ 22	$	$ 1,749
FES	702	18		720	1,043	3		1,046
OE	119	1		120	55			55
TE	14			14	72			72
JCP&L	278	11		289	271	9		280
Met-Ed	130	5		135	120	5		125
Penelec	161	5		166	166	5		171
Equity securities								
FirstEnergy	$ 250	$ 24	$	$ 274	$ 252	$ 43	$	$ 295
JCP&L	74	4		78	74	11		85
Met-Ed	117	14		131	117	23		140

Penelec	59	6	65	61	9	70

(1) Excludes cash balances: FirstEnergy $463 million; FES $388 million; OE $6 million; TE $61 million; JCP&L $3 million; Met-Ed $(2) million and Penelec - $7 million.

(2) Excludes cash balances: FirstEnergy $137 million; FES $43 million; OE - $66 million; TE $2 million; JCP&L $3 million and Penelec $23 million.

Proceeds from the sale of investments in available-for-sale securities, realized gains and losses on those sales, and interest and dividend income for the six-month period ended June 30, 2010 and 2009 were as follows:

June 30, 2010	FirstEnergy	FES	OE	TE	JCP&L	Met-Ed	Penelec
			(In millions)				
Proceeds from sales	$ 1,916	$ 957	$ 60	$ 107	$ 281	$ 377	$ 134
Realized gains	83	54	2	3	9	9	6
Realized losses	86	58			9	12	7
Interest and dividend income	37	22	1	1	7	3	3

June 30, 2009	FirstEnergy	FES	OE	TE	JCP&L	Met-Ed	Penelec
			(In millions)				
Proceeds from sales	$ 1,001	$ 537	$ 25	$ 77	$ 245	$ 63	$ 54
Realized gains	30	24	-	3	3	1	-
Realized losses	91	58	3	-	11	12	7
Interest and dividend income	30	14	2	1	7	3	3

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 June 30, 2010 and December 31, 2009 (excluding emission allowances, employee benefits, cost method investments and equity method investments of $251 million and $264 million, respectively, that are not required to be disclosed):

	June 30, 2010				December 31, 2009			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
				(In millions)				
Debt Securities								
FirstEnergy	$ 487	$ 93	$	$ 580	$ 544	$ 72	$	$ 616
OE	205	55		260	217	29		246
CEI	340	38		378	389	43		432

Notes Receivable

The following table provides the approximate fair value and related carrying amounts of notes receivable as of June 30, 2010 and December 31, 2009:

	June 30, 2010		December 31, 2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
		(In millions)		
Notes Receivable				
FirstEnergy	$ 36	$ 34	$ 36	$ 35
FES			2	1
TE	104	117	124	141

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.

(C) RECURRING FAIR VALUE MEASUREMENTS

Fair value is the price that would be received for an asset or paid to transfer a liability (exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between willing market participants on the measurement date. A fair value hierarchy has been established that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy are as follows:

Level 1 Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those where transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. FirstEnergy s Level 1 assets and liabilities primarily consist of exchange-traded derivatives and equity securities listed on active exchanges that are held in various trusts.

Level 2 Pricing inputs are either directly or indirectly observable in the market as of the reporting date, other than quoted prices in active markets included in Level 1. FirstEnergy s Level 2 assets and liabilities consist primarily of investments in debt securities held in various trusts and commodity forwards. Additionally, Level 2 includes those financial instruments that are valued using models or other valuation methodologies based on assumptions that are observable in the marketplace throughout the full term of the instrument and can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Instruments in this category include non-exchange-traded derivatives such as forwards and certain interest rate swaps.

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Level 3 Pricing inputs include inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management s best estimate of fair value. FirstEnergy develops its view of the future market price of key commodities through a combination of market observation and assessment (generally for the short term) and fundamental modeling (generally for the long term). Key fundamental electricity model inputs are generally directly observable in the market or derived from publicly available historic and forecast data. Some key inputs reflect forecasts published by industry leading consultants who generally employ similar fundamental modeling approaches. Fundamental model inputs and results, as well as the selection of consultants, reflect the consensus of appropriate FirstEnergy management. Level 3 instruments include those that may be more structured or otherwise tailored to customers needs. FirstEnergy s Level 3 instruments consist exclusively of NUG contracts.

FirstEnergy utilizes market data and assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. FirstEnergy primarily applies the market approach for recurring fair value measurements using the best information available. Accordingly, FirstEnergy maximizes the use of observable inputs and minimizes the use of unobservable inputs.

The following tables set forth financial assets and financial liabilities that are accounted for at fair value by level within the fair value hierarchy as of June 30, 2010 and December 31, 2009. Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. FirstEnergy s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the fair valuation of assets and liabilities and their placement within the fair value hierarchy levels.

	Recurring Fair Value Measures as of June 30, 2010						
	Level 1						
	FirstEnergy	**FES**	**OE**	**TE**	**JCP&L**	**Met-Ed**	**Penelec**
				(In millions)			
Assets							
Nuclear Decommissioning Trust Investments							
Equity securities consumer products	$ 122	$	$	$	$ 35	$ 58	$ 29
Equity securities technology	51				15	24	12
Equity securities utilities & energy	52				15	25	12
Equity securities financial	42				12	20	10
Equity securities other	8				2	4	2
Total Assets(1)	$ 275	$	$	$	$ 79	$ 131	$ 65
Liabilities							
Derivatives commodity contracts	$ 5	$ 5	$	$	$	$	$
Total Liabilities	$ 5	$ 5	$	$	$	$	$

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	FirstEnergy	FES	OE	Level 2 TE *(In millions)*	JCP&L	Met-Ed	Penelec
Assets							
Nuclear Decommissioning Trust Investments							
U.S. government debt securities	$ 538	$ 265	$ 121	$ 14	$ 36	$ 92	$ 10
U.S. state debt securities	94				31	2	61
Foreign government debt securities	297	297					
Corporate debt securities	225	158			20	42	5
Other	458	388	5	62	1	1	1
Total nuclear decommissioning trust investments	$ 1,612	$ 1,108	$ 126	$ 76	$ 88	$ 137	$ 77
Rabbi Trust Investments							
Equity securities financial	$ 1	$	$	$	$	$	$
Other	12		1				
Total rabbi trust investments	$ 13	$	$ 1	$	$	$	$
Nuclear Fuel Disposal Trust Investments							
U.S. state debt securities	$ 196	$	$	$	$ 196	$	$
Other	8				8		
Total nuclear fuel disposal trust investments	$ 204	$	$	$	$ 204	$	$
NUG Trust Investments							
U.S. state debt securities	$ 97	$	$	$	$	$	$ 97
Total NUG trust investments	$ 97	$	$	$	$	$	$ 97
Derivatives							
Commodity contracts	$ 111	$ 102	$	$	$ 2	$ 5	$ 2
Interest rate contracts	62						

Total derivatives contracts	$ 173	$ 102	$	$	$ 2	$ 5	$ 2
Total Assets(1)	$ 2,099	$ 1,210	$ 127	$ 76	$ 294	$ 142	$ 176
Liabilities							
Derivatives							
Commodity contracts	$ 273	$ 273	$	$	$	$	$
Total Liabilities	$ 273	$ 273	$	$	$	$	$

				Level 3			
	FirstEnergy	**FES**	**OE**	**TE**	**JCP&L**	**Met-Ed**	**Penelec**
				(In millions)			
Assets							
Derivatives NUG contracts(2)	$ 134	$	$	$	$ 7	$ 121	$ 6
Liabilities							
Derivatives NUG contracts(2)	$ 691	$	$	$	$ 378	$ 159	$ 154

(1) Excludes $(7) million of receivables, payables and accrued income.

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

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	Recurring Fair Value Measures as of December 31, 2009 Level 1						
	FirstEnergy	**FES**	**OE**	**TE**	**JCP&L**	**Met-Ed**	**Penelec**
				(In millions)			
Assets							
Nuclear Decommissioning Trust Investments							
Equity securities consumer products	$ 130	$	$	$	$ 38	$ 59	$ 33
Equity securities technology	57				17	26	14
Equity securities utilities & energy	59				17	27	15
Equity securities financial	39				12	17	10
Equity securities other	9				3	4	2
Total Assets(1)	$ 294	$	$	$	$ 87	$ 133	$ 74
Liabilities							
Derivatives commodity contracts	$ 11	$ 11	$	$	$	$	$
Total Liabilities	$ 11	$ 11	$	$	$	$	$

	FirstEnergy	FES	OE	Level 2 TE *(In millions)*	JCP&L	Met-Ed	Penelec
Assets							
Nuclear Decommissioning Trust Investments							
U.S. government debt securities	$ 558	$ 306	$ 118	$ 72	$ 23	$ 30	$ 9
U.S. state debt securities	188	15			41	82	50
Foreign government debt securities	279	279					
Corporate debt securities	484	443			15	20	6
Other	35	29	2		1	2	1
Total nuclear decommissioning trust investments	$ 1,544	$ 1,072	$ 120	$ 72	$ 80	$ 134	$ 66
Rabbi Trust Investments							
Equity securities financial	$ 1	$	$	$	$	$	$
Other	9						
Total rabbi trust investments	$ 10	$	$	$	$	$	$
Nuclear Fuel Disposal Trust Investments							
U.S. state debt securities	$ 189	$	$	$	$ 189	$	$
Other	11				11		
Total nuclear fuel disposal trust investments	$ 200	$	$	$	$ 200	$	$
NUG Trust Investments							
U.S. state debt securities	$ 101	$	$	$	$	$	$ 101
Other	19						19
Total NUG trust investments	$ 120	$	$	$	$	$	$ 120
Derivatives Commodity Contracts	$ 34	$ 15	$	$	$ 5	$ 9	$ 5

Other	$ 1	$	$	$	$	$	$
Total Assets[1]	$ 1,909	$ 1,087	$ 120	$ 72	$ 285	$ 143	$ 191
Liabilities							
Derivatives commodity contracts	$ 224	$ 224	$	$	$	$	$
Total Liabilities	$ 224	$ 224	$	$	$	$	$

				Level 3			
	FirstEnergy	**FES**	**OE**	**TE**	**JCP&L**	**Met-Ed**	**Penelec**
				(In millions)			
Assets							
Derivatives NUG contracts[2]	$ 200	$	$	$	$ 9	$ 176	$ 15
Liabilities							
Derivatives NUG contracts[2]	$ 643	$	$	$	$ 399	$ 143	$ 101

(1) Excludes $21 million of receivables, payables and accrued income.

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

The determination of the above fair value measures takes into consideration various factors. These factors include nonperformance risk, including counterparty credit risk and the impact of credit enhancements (such as cash deposits, LOCs and priority interests). The impact of nonperformance risk was immaterial in the fair value measurements.

The following tables set forth a reconciliation of changes in the fair value of NUG contracts classified as Level 3 in the fair value hierarchy for the three and six months ended June 30, 2010 and 2009 (in millions):

	FirstEnergy	JCP&L	Met-Ed	Penelec
Balance as of January 1, 2010	$ (444)	$ (391)	$ 33	$ (86)
Settlements[(1)]	146	70	36	40
Unrealized losses[(1)]	(259)	(50)	(107)	(102)
Balance as of June 30, 2010	$ (557)	$ (371)	$ (38)	$ (148)
Balance as of April 1, 2010	$ (590)	$ (394)	$ (30)	$ (166)
Settlements[(1)]	68	30	19	19
Unrealized losses[(1)]	(35)	(7)	(27)	(1)
Balance as of June 30, 2010	$ (557)	$ (371)	$ (38)	$ (148)

	FirstEnergy	JCP&L	Met-Ed	Penelec
Balance as of January 1, 2009	$ (332)	$ (518)	$ 150	$ 36
Settlements[(1)]	179	90	43	47
Unrealized losses[(1)]	(383)	(38)	(170)	(176)
Balance as of June 30, 2009	$ (536)	$ (466)	$ 23	$ (93)
Balance as of April 1, 2009	$ (476)	$ (518)	$ 76	$ (34)
Settlements[(1)]	96	44	26	27
Unrealized gains (losses)[(1)]	(156)	8	(79)	(86)
Balance as of June 30, 2009	$ (536)	$ (466)	$ 23	$ (93)

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

4. 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 uses a variety of derivative instruments, including forward contracts, options, futures contracts and swaps. The derivatives are used for risk management purposes. In addition to derivatives, FirstEnergy also enters into master netting agreements with certain third parties. FirstEnergy s Risk Policy Committee, comprised of members of senior management, 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 practices.
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 at cost under the accrual method of accounting. The changes in the fair value of derivative instruments that do not meet the normal purchases and normal sales criteria are included in purchased power, other expense, unrealized gain (loss) on derivative hedges in other comprehensive income (loss), or as part of the value of the hedged item. Based on derivative contracts held as of June 30, 2010, an adverse 10% change in commodity prices would decrease net income by approximately $9 million ($6 million net of tax) during the next twelve months. A hypothetical 10% increase in the interest rates associated with variable-rate debt would decrease net income by less than $1 million for the three and six months ended June 30, 2010.

Cash Flow Hedges

FirstEnergy has used forward starting swap agreements to hedge a portion of the consolidated interest rate risk associated with anticipated issuances of fixed-rate, long-term debt securities of its subsidiaries. These derivatives were treated as cash flow hedges, protecting against the risk of changes in future interest payments resulting from changes in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance. As of June 30, 2010, no forward starting swap agreements were outstanding.

Total unamortized losses included in AOCL associated with prior interest rate cash flow hedges totaled $109 million ($71 million net of tax) as of June 30, 2010. Based on current estimates, approximately $11 million will be amortized to interest expense during the next twelve months. The table below provides the activity of AOCL related to interest rate cash flow hedges as of June 30, 2010 and 2009.

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	Three Months Ended June 30		Six Months Ended June 30	
	2010	2009	2010	2009
	(In millions)		(In millions)	
Effective Portion				
Gain Recognized in AOCL	$	$ 2	$	$
Reclassification from AOCL into Interest Expense	(3)	(6)	(6)	(11)

Fair Value Hedges

FirstEnergy uses 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 derivatives are 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. In May of 2010, FirstEnergy terminated fixed-for-floating interest rate swap agreements with a notional value of $3.15 billion, which resulted in cash proceeds of $43.1 million. These proceeds will generally be amortized to earnings over the life of the underlying debt.

Effective June 1, 2010, FirstEnergy executed multiple fixed-for-floating interest rate swap agreements with a combined notional value of $3.2 billion, which essentially replaced the swap agreements terminated in May of 2010. As of June 30, 2010, the debt underlying the $3.2 billion outstanding notional amount of interest rate swaps had a weighted average fixed interest rate of 6%, which the swaps have converted to a current weighted average variable rate of 4%.

On July 16, 2010, FirstEnergy terminated these fixed-for-floating interest rate swap agreements with a notional value of $3.2 billion, which resulted in cash proceeds of $83.6 million. These proceeds will be amortized to earnings over the life of the underlying debt. While FirstEnergy currently does not have any interest rate swaps outstanding, costs associated with entering into future swap transactions may be increased as a result of the recent passage of the Dodd-Frank Wall Street Reform and Consumer Protection Act, which requires increased regulation of swaps, swap dealers and major swap participants.

The following tables summarize the fair value of interest rate swaps in FirstEnergy s Consolidated Balance Sheets:

Derivative Assets	**Fair Value**		**Derivative Liabilities**	**Fair Value**	
	June 30, 2010	**December 31, 2009**		**June 30, 2010**	**December 31, 2009**
	(In millions)			*(In millions)*	
Fair Value Hedges			Fair Value Hedges		
Interest Rate Swaps	$ 62	$	Interest Rate Swaps	$	$
Noncurrent Assets	$ 62	$	Noncurrent Liabilities	$	$

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.

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The following tables summarize the fair value of commodity derivatives in FirstEnergy s Consolidated Balance Sheets:

Derivative Assets	**Fair Value** June 30, 2010	**Fair Value** December 31, 2009	**Derivative Liabilities**	**Fair Value** June 30, 2010	**Fair Value** December 31, 2009
	(In millions)			*(In millions)*	
Cash Flow Hedges			Cash Flow Hedges		
Electricity Forwards			Electricity Forwards		
Current Assets	$ 40	$ 3	Current Liabilities	$ 50	$ 7
NonCurrent Assets	57	11	NonCurrent Liabilities	54	12
Natural Gas Futures			Natural Gas Futures		
Current Assets			Current Liabilities	4	9
NonCurrent Assets			NonCurrent Liabilities		
Other			Other		
Current Assets			Current Liabilities	1	2
NonCurrent Assets			NonCurrent Liabilities		
	$ 97	$ 14		$ 109	$ 30

Derivative Assets	**Fair Value** June 30, 2010	**Fair Value** December 31, 2009	**Derivative Liabilities**	**Fair Value** June 30, 2010	**Fair Value** December 31, 2009
	(In millions)			*(In millions)*	
Economic Hedges			Economic Hedges		
NUG Contracts			NUG Contracts		
Power Purchase			Power Purchase		
Contract Asset	$ 134	$ 200	Contract Liability	$ 691	$ 643
Other			Other		
Current Assets	4		Current Liabilities	114	106
NonCurrent Assets	10	19	NonCurrent Liabilities	55	97
	148	219		860	846
Total Commodity Derivatives	$ 245	$ 233	Total Commodity Derivatives	$ 969	$ 876

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 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. Derivative instruments are not used in quantities greater than forecasted needs. The following table summarizes the volume of FirstEnergy s outstanding derivative transactions as of June 30, 2010:

	Purchases	**Sales**	**Net**	**Units**
		(In thousands)		

Electricity Forwards	21,596	(19,965)	1,631	MWH
Heating Oil Futures	2,100		2,100	Gallons
Natural Gas Futures	1,250	(1,000)	250	mmBtu

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The effect of derivative instruments on the consolidated statements of income and comprehensive income for the three and six months ended June 30, 2010 and 2009, for instruments designated in cash flow hedging relationships and not in hedging relationships, respectively, are summarized in the following tables:

	Three Months Ended June 30,			
Derivatives in Cash Flow Hedging Relationships	**Electricity Forwards**	**Natural Gas Futures**	**Heating Oil Futures**	**Total**
	(In millions)			
2010				
Gain (Loss) Recognized in AOCL (Effective Portion)	$ (8)	$	$	$ (8)
Effective Gain (Loss) Reclassified to: [1]				
Purchased Power Expense	(7)			(7)
Fuel Expense		(3)	(1)	(4)
2009				
Gain (Loss) Recognized in AOCL (Effective Portion)	$ 6	$	$ 2	$ 8
Effective Gain (Loss) Reclassified to: [1]				
Purchased Power Expense	1			1
Fuel Expense		(4)	(4)	(8)

	Six Months Ended June 30,			
Derivatives in Cash Flow Hedging Relationships	**Electricity Forwards**	**Natural Gas Futures**	**Heating Oil Futures**	**Total**
	(In millions)			
2010				
Gain (Loss) Recognized in AOCL (Effective Portion)	$ (13)	$ (1)	$	$ (14)
Effective Gain (Loss) Reclassified to: [1]				
Purchased Power Expense	(11)			(11)
Fuel Expense		(6)	(2)	(8)
2009				
Gain (Loss) Recognized in AOCL (Effective Portion)	$ 4	$ (7)	$ 1	$ (2)
Effective Gain (Loss) Reclassified to: [1]				
Purchased Power Expense	(17)			(17)
Fuel Expense		(4)	(8)	(12)

(1) The ineffective portion was immaterial.

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Derivatives Not in Hedging Relationships	Three Months Ended June 30, NUG Contracts	Other	Total
		(In millions)	
2010			
Unrealized Gain (Loss) Recognized in:			
Purchased Power Expense	$	$ 35	$ 35
Regulatory Assets (2)	(35)		(35)
	$ (35)	$ 35	$
Realized Gain (Loss) Reclassified to:			
Purchased Power Expense	$	$ (31)	$ (31)
Regulatory Assets (2)	(68)		(68)
	$ (68)	$ (31)	$ (99)
2009			
Unrealized Gain (Loss) Recognized in:			
Fuel Expense (1)	$	2	$ 2
Regulatory Assets (2)	(156)	$	(156)
	$ (156)	$ 2	$ (154)
Realized Gain (Loss) Reclassified to:			
Fuel Expense (1)	$	$	$
Regulatory Assets (2)	(96)		(96)
	$ (96)	$	$ (96)

Derivatives Not in Hedging Relationships	Six Months Ended June 30, NUG Contracts	Other	Total
		(In millions)	
2010			
Unrealized Gain (Loss) Recognized in:			
Purchased Power Expense	$	$ (17)	$ (17)
Regulatory Assets (2)	(259)		(259)
	$ (259)	$ (17)	$ (276)
Realized Gain (Loss) Reclassified to:			
Purchased Power Expense	$	$ (56)	$ (56)

Regulatory Assets [2]		(146)		9		(137)
	$	(146)	$	(47)	$	(193)
2009						
Unrealized Gain (Loss) Recognized in:						
Fuel Expense [1]	$		$	2	$	2
Regulatory Assets [2]		(383)				(383)
		(383)	$	2	$	(381)
Realized Gain (Loss) Reclassified to:						
Fuel Expense [1]	$		$	(1)	$	(1)
Regulatory Assets [2]		(179)		10		(169)
	$	(179)	$	9	$	(170)

(1) The realized gain (loss) is reclassified upon termination of the derivative instrument.

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

Total unamortized losses included in AOCL associated with commodity derivatives were $11 million ($7 million net of tax) as of June 30, 2010, as compared to $15 million ($9 million net of tax) as of December 31, 2009. The net of tax change resulted from a net $10 million increase related to current hedging activity and a $12 million decrease due to net hedge losses reclassified to earnings during the first six months of 2010. Based on current estimates, approximately $10 million (net of tax) of the net deferred losses on derivative instruments in AOCL as of June 30, 2010 are expected to be reclassified to earnings during the next twelve months as hedged transactions occur. The fair value of these derivative instruments fluctuate from period to period based on various market factors.

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Many of FirstEnergy s commodity derivatives contain credit risk features. As of June 30, 2010, FirstEnergy posted $194 million of collateral related to net liability positions and held no counterparties funds related to asset positions. The collateral FirstEnergy has posted relates to both derivative and non-derivative contracts. FirstEnergy s largest derivative counterparties fully collateralize all derivative transactions. Certain commodity derivative contracts include credit risk-related contingent features that would require FirstEnergy to post additional collateral if the credit rating for its debt were to fall below investment grade. The aggregate fair value of derivative instruments with credit risk-related contingent features that are in a liability position on June 30, 2010 was $177 million, for which $194 million in collateral has been posted. If FirstEnergy s credit rating were to fall below investment grade, it would be required to post $37 million of additional collateral related to commodity derivatives.

5. 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 s net pension and OPEB expense for the three months ended June 30, 2010 and 2009 was $21 million and $38 million, respectively. FirstEnergy s net pension and OPEB expense for the six months ended June 30, 2010 and 2009 was $45 million and $80 million, respectively. The components of FirstEnergy s net pension and other postretirement benefit costs (including amounts capitalized) for the three and six months ended June, 2010 and 2009, consisted of the following:

	Three Months Ended June 30		Six Months Ended June 30	
Pension Benefits	**2010**	**2009**	**2010**	**2009**
	(In millions)			
Service cost	$ 25	$ 22	$ 49	$ 43
Interest cost	79	80	157	159
Expected return on plan assets	(90)	(81)	(181)	(162)
Amortization of prior service cost	3	3	6	7
Recognized net actuarial loss	47	42	94	85
Net periodic cost	**$ 64**	**$ 66**	**$ 125**	**$ 132**

	Three Months Ended June 30		Six Months Ended June 30	
Other Postretirement Benefits	**2010**	**2009**	**2010**	**2009**
	(In millions)			
Service cost	$ 3	$ 4	$ 5	$ 8
Interest cost	11	18	22	38
Expected return on plan assets	(9)	(9)	(18)	(18)
Amortization of prior service cost	(48)	(41)	(96)	(79)
Recognized net actuarial loss	15	15	30	31
Net periodic cost	**$ (28)**	**$ (13)**	**$ (57)**	**$ (20)**

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Pension and other postretirement benefit obligations are allocated to FirstEnergy s subsidiaries employing the plan participants. The net periodic pension costs and net periodic other postretirement benefit costs (including amounts capitalized) recognized by FirstEnergy s subsidiaries for the three and six months ended June 30, 2010 and 2009 were as follows:

	Three Months Ended June 30		Six Months Ended June 30	
Pension Benefit Cost (Credit)	**2010**	**2009**	**2010**	**2009**
		(In millions)		
FES	$ 22	$ 18	$ 44	$ 36
OE	6	7	11	14
CEI	5	5	11	10
TE	2	2	4	3
JCP&L	6	9	12	18
Met-Ed	3	6	5	11
Penelec	5	4	9	9
Other FirstEnergy Subsidiaries	15	15	29	31
	$ 64	**$ 66**	**$ 125**	**$ 132**

	Three Months Ended June 30		Six Months Ended June 30	
Other Postretirement Benefit Cost (Credit)	**2010**	**2009**	**2010**	**2009**
		(In millions)		
FES	$ (7)	$ (3)	$ (13)	$ (4)
OE	(6)	(3)	(12)	(5)
CEI	(1)		(3)	1
TE			(1)	1
JCP&L	(2)	(1)	(4)	(2)
Met-Ed	(2)	(1)	(4)	(2)
Penelec	(2)	(1)	(4)	(2)
Other FirstEnergy Subsidiaries	(8)	(4)	(16)	(7)
	$ (28)	**$ (13)**	**$ (57)**	**$ (20)**

6. VARIABLE INTEREST ENTITIES

On January 1, 2010, FirstEnergy adopted the amendments to the consolidation topic addressing VIEs. This standard requires that FirstEnergy and its subsidiaries perform a qualitative analysis 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. This standard also requires an ongoing reassessment of the primary beneficiary of a VIE and eliminates the quantitative approach previously required for determining whether an entity is the primary beneficiary. There was no impact to FirstEnergy or its subsidiaries as a result of the adoption of this standard.

FirstEnergy s consolidated financial statements include the accounts of entities in which it has a controlling financial interest. 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 is the result of net losses of the noncontrolling interests ($15 million) and distributions to owners ($4 million) for the six months ended June 30, 2010.

FirstEnergy consolidates certain VIEs in which it has financial control through disproportionate economics in its equity and debt investments in the entities. These VIEs include: FEV s joint venture in the Signal Peak mining and coal transportation operations; 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, of which $326 million was outstanding as of June 30, 2010.

In order to evaluate contracts under the consolidation guidance, FirstEnergy aggregated contracts into two categories based on similar risk characteristics and significance as follows:

Power Purchase Agreements

FirstEnergy evaluated its power purchase agreements and determined that certain NUG entities may be VIEs to the extent they own a plant that sells substantially all of its output to the Utilities and the contract price for power is correlated with the plant s variable costs of production. FirstEnergy, through its subsidiaries JCP&L, Met-Ed and Penelec, maintains 21 long-term power purchase agreements with NUG entities. The agreements were entered into pursuant to the Public Utility Regulatory Policies Act of 1978. 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 two of these entities, neither JCP&L, nor Met-Ed nor Penelec have variable interests in the entities or the entities are governmental or not-for-profit organizations not within the scope of consolidation consideration for VIEs. JCP&L may hold variable interests in the remaining two entities, which sell their output at variable prices that correlate to some extent with the operating costs of the plants. However, FirstEnergy applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities.

Since JCP&L has no equity or debt interests in the NUG entities, its maximum exposure to loss relates primarily to the above-market costs it incurs for power. FirstEnergy expects any above-market costs it incurs to be recovered from customers. Purchased power costs related to the two contracts that may contain a variable interest were $53 million and $48 million for the three months ended June 30, 2010, and 2009, respectively and $117 million and $115 million for the six months ended June 30, 2010 and 2009, respectively.

Loss Contingencies

FirstEnergy has variable interests in certain sale-leaseback transactions. FirstEnergy concluded that it 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-leaseback agreements upon the occurrence of certain contingent events that each company considers unlikely to occur. The maximum exposure under these provisions represents the net amount of casualty value payments due upon the occurrence of specified casualty events that render the applicable plant worthless. 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:

	Maximum Exposure	Discounted Lease Payments, net[1]	Net Exposure
		(In millions)	
FES	$ 1,352	$ 1,165	$ 187
OE	693	499	194
CEI[2]	662	70	592
TE[2]	662	339	323

(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.

7. 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. After reaching a settlement at appeals related primarily to the capitalization of certain costs for the tax years 2005-2008, as well as reaching a settlement on an unrelated state tax matter in the second quarter of 2010, FirstEnergy recognized approximately $70 million of net tax benefits, including $13 million that favorably affected FirstEnergy s effective tax rate for the second quarter of 2010. The remaining portion of the tax benefit recognized in the first six months of 2010 increased FirstEnergy s accumulated deferred income taxes for the settled temporary tax item. Upon completion of the federal tax examination for the 2007 tax year in the first quarter of 2009, FirstEnergy recognized $13 million in tax benefits, which favorably affected FirstEnergy s effective tax rate. There were no material changes to FirstEnergy s unrecognized tax benefits in the second quarter of 2009.

As of June 30, 2010, it is reasonably possible that approximately $11 million of the unrecognized benefits may be resolved within the next twelve months, of which approximately $11 million, if recognized, would affect FirstEnergy s effective tax rate. The potential decrease in the amount of unrecognized tax benefits is primarily associated with issues related to gains and losses recognized on the disposition of assets and various other 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 reversal of accrued interest associated with the recognized tax benefits noted above favorably affected FirstEnergy s effective tax rate by $11 million in the first six months of 2010. During the first six months of 2009, there were no material changes to the amount of interest accrued. The net amount of accumulated interest accrued as of June 30, 2010 was $6 million, as compared to $21 million as of December 31, 2009.

As a result of the Patient Protection and Affordable Care Act and the Health Care and Education Affordability Reconciliation Act signed into law on March 23, 2010 and March 30, 2010, respectively, 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 are 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. This change reflects the anticipated increase in income taxes that will occur as a result of the change in tax law.

FirstEnergy has tax returns that are under review at the audit or appeals level by the IRS and state tax authorities. All state jurisdictions are open from 2001-2008. The IRS began reviewing returns for the years 2001-2003 in July 2004 and several items were under appeal. In the fourth quarter of 2009, these items were settled at appeals and sent to Joint Committee on Taxation for final review. The federal audits for years 2004-2006 were completed in the third quarter of 2008 and several items are under appeal. The IRS began auditing the year 2007 in February 2007 under its Compliance Assurance Process program and was completed in the first quarter of 2009 with two items under appeal. In the second quarter of 2010, the items under appeal for tax years 2006 and 2007 were settled and sent to Joint Committee on Taxation for final review. The IRS began auditing the year 2008 in February 2008 and the audit was completed in July 2010 with one item under appeal. The 2009 tax year audit began in February 2009 and the 2010 tax year began in February 2010. Neither audit is expected to close before December 2010. 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 or results of operations.

8. 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 June 30, 2010, outstanding guarantees and other assurances aggregated approximately $3.9 billion, consisting primarily of parental guarantees ($0.9 billion), subsidiaries guarantees ($2.5 billion), surety bonds and LOCs ($0.5 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. The likelihood is remote that such parental guarantees of $0.3 billion (included in the $0.9 billion discussed above) as of June 30, 2010 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 a LOC or accelerated payments may be required of the subsidiary. As of June 30, 2010, FirstEnergy s maximum exposure under these collateral provisions was $451 million, consisting of $37 million due to material adverse event contractual clauses, $83 million due to an acceleration of payment or funding obligation, and $331 million due to a below investment grade credit rating. 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 $609 million, consisting of $56 million due to material adverse event contractual clauses, $83 million related to an acceleration of payment or funding obligation, and $470 million due to a below investment grade credit rating.

Most of FirstEnergy s surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related guarantees of $90 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, FES contracts, including power contracts with affiliates awarded through competitive bidding processes, typically contain margining provisions which require the posting of cash or LOCs in amounts determined by future power price movements. Based on FES power portfolio as of June 30, 2010, and forward prices as of that date, FES has posted collateral of $245 million. Under a hypothetical adverse change in forward prices (95% confidence level change in forward prices over a one year time horizon), FES would be required to post an additional $107 million. Depending on the volume of forward contracts and future price movements, FES could be required to post higher amounts for margining.

In connection with FES obligations to post and maintain collateral under the two-year PSA entered into by FES and the Ohio Companies following the CBP auction on May 13-14, 2009, NGC entered into a Surplus Margin Guaranty in an amount up to $500 million. The Surplus Margin Guaranty is secured by an NGC FMB issued in favor of the Ohio Companies.

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 will have claims against each of FES, FGCO and NGC regardless of whether their primary obligor is FES, FGCO or NGC.

(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 NO_X emissions regulations under the CAA. FirstEnergy complies with SO_2 and NOx reduction requirements under the CAA and State Implementation Plan(s) under the CAA (SIPs) 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.

The Sammis, Burger, Eastlake and Mansfield coal-fired plants are operated under a consent decree with the EPA and DOJ that requires reductions of NO_X and SO_2 emissions through the installation of pollution control devices or repowering. OE and Penn are subject to stipulated penalties for failure to install and operate such pollution controls or complete repowering in accordance with that agreement. Capital expenditures necessary to complete requirements of the consent decree, including repowering Burger Units 4 and 5 for biomass fuel combustion, are currently estimated to be approximately $399 million for 2010-2012.

In 2007, PennFuture filed a citizen suit under the CAA, alleging violations of air pollution laws at the Bruce Mansfield Plant, including opacity limitations, in the U.S. District Court for the Western District of Pennsylvania. In July 2008, three additional complaints were filed against FGCO in the U.S. District Court for the Western District of Pennsylvania also seeking damages based on 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. A settlement was reached with PennFuture. FGCO believes the claims of the remaining plaintiffs are without merit and intends to defend itself against the allegations made in those three complaints.

The states of New Jersey and Connecticut filed CAA citizen suits in 2007 alleging NSR violations at the Portland Generation Station against Reliant (the current owner and operator), Sithe Energy (the purchaser of the Portland Station from Met-Ed in 1999), GPU and Met-Ed. Specifically, these suits allege that modifications at Portland Units 1 and 2 occurred between 1980 and 2005 without preconstruction NSR or permitting under 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.

In January 2009, the EPA issued a NOV to Reliant alleging NSR violations at the Portland Generation Station based on modifications dating back to 1986 and also alleged NSR violations at the Keystone and Shawville Stations based on modifications dating back to 1984. Met-Ed, JCP&L as the former owner of 16.67% of the Keystone Station, and Penelec, as former owner and operator of the Shawville Station, are unable to predict the outcome of this matter.

In June 2008, the EPA issued a Notice and Finding of Violation to Mission Energy Westside, Inc. alleging that modifications at the Homer City Power Station occurred since 1988 to the present without preconstruction NSR permitting under the CAA s PSD program. In May 2010, the EPA issued a second NOV to Mission Energy Westside, Inc., Penelec, NYSEG and others that have had an ownership interest in the Homer City Power Station containing in all material respects identical allegations as the June 2008 NOV. On July 20, 2010, the states of New York and Pennsylvania provided Mission Energy Westside, Inc., Penelec, NYSEG and others that have had an ownership interest in the Homer City Power Station a notification required 60 days prior to filing a citizen suit under the CAA. Mission Energy is seeking indemnification from Penelec, the co-owner and operator of the Homer City Power Station prior to its sale in 1999. The scope of Penelec s indemnity obligation to and from Mission Energy is under dispute and Penelec is unable to predict the outcome of this matter.

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 generating 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 scheduled maintenance at the Eastlake generating plant may constitute a major modification under the NSR provision of the CAA. Later in 2009, FGCO received another information request regarding emission projections for the Eastlake generating plant. 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.

National Ambient Air Quality Standards

The EPA s CAIR requires reductions of NO_X 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 NO_X emissions to 1.3 million tons annually. In 2008, the U.S. Court of Appeals for the District of Columbia 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 NO_X 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 2010, the EPA proposed the Clean Air Transport Rule (CATR) to replace CAIR, which remains in effect until the EPA finalizes CATR. CATR requires reductions of NO_X and SO_2 emissions in two phases (2012 and 2014), ultimately capping SO_2 emissions in affected states to 2.6 million tons annually and NO_X emissions to 1.3 million tons annually. The EPA proposed a preferred regulatory approach that allows trading of NO_X and SO_2 emission allowances between power plants located in the same state with severe limits on interstate trading and two alternative approaches the first eliminates interstate trading of NO_X and SO_2 emission allowances and the second eliminates trading of NO_X and SO_2 emission allowances in its entirety. Depending on the actions taken by the EPA with respect to CATR, the proposed MACT regulations discussed below, and any future regulations that are ultimately implemented, FGCO s future cost of compliance may be substantial. Management is currently assessing the impact of these environmental proposals and other factors on FGCO s facilities, particularly on the operation of its smaller, non-supercritical units. For example, management may decide to idle certain of these units or operate them on a seasonal basis until developments clarify.

Hazardous Air Pollutant Emissions

The EPA s CAMR provides for a cap-and-trade program to reduce mercury emissions from coal-fired power plants in two phases; initially, capping nationwide emissions of mercury at 38 tons by 2010 (as a co-benefit from implementation of SO_2 and NO_X emission caps under the EPA s CAIR program) and 15 tons per year by 2018. The U.S. Court of Appeals for the District of Columbia, at the urging of several states and environmental groups vacated the CAMR, ruling that the EPA failed to take the necessary steps to de-list coal-fired power plants from its hazardous air pollutant program and, therefore, could not promulgate a cap-and-trade program. The EPA entered into a consent decree requiring it to propose maximum achievable control technology (MACT) regulations for mercury and other hazardous air pollutants by March 16, 2011, and to finalize the regulations by November 16, 2011. On April 29, 2010, the EPA issued proposed MACT regulations requiring emissions reductions of mercury and other hazardous air pollutants from non-electric generating unit boilers, including boilers which do not use fossil fuels such as the proposed Burger biomass repowering project. If finalized, the non-electric generating unit MACT regulations could also provide precedent for MACT standards applicable to electric generating units. Depending on the action taken by the EPA and on how any future regulations are ultimately implemented, FGCO s future cost of compliance with MACT regulations may be substantial and changes to FGCO s operations may result.

Pennsylvania has submitted a new mercury rule for EPA approval that does not provide a cap-and-trade approach as in the CAMR, but rather follows a command-and-control approach imposing emission limits on individual sources. On December 23, 2009, the Supreme Court of Pennsylvania affirmed the Commonwealth Court of Pennsylvania ruling that Pennsylvania s mercury rule is unlawful, invalid and unenforceable and enjoined the Commonwealth from continued implementation or enforcement of that rule.

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, on June 26, 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, ensuring that 10% of electricity used in the United States comes from renewable sources by 2012, increasing to 25% by 2025, and implementing an economy-wide cap-and-trade program to reduce GHG emissions by 80% by 2050. State activities, primarily the northeastern states participating in the Regional Greenhouse Gas Initiative and western states, led by California, have coordinated efforts to develop regional strategies to control emissions of certain GHGs.

The EPA has authority under the CAA to regulate air pollutants from electric generating plants and other facilities. In September 2009, the EPA finalized a national GHG emissions collection and reporting rule that will require FirstEnergy to measure GHG emissions commencing in 2010 and submit reports commencing in 2011. 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 GHG increase the threat of climate change. 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 will 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 program would be required. The EPA established an emissions applicability threshold of 75,000 tons per year (tpy) of carbon dioxide equivalents (CO2e) effective January 2, 2011 for existing facilities under the CAA s Prevention of Significant Determination (PSD) program, but until July 1, 2011 that emissions applicability threshold will only apply if PSD is triggered by non-carbon dioxide pollutants.

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 which recognized the scientific view that the increase in global temperature should be below two degrees Celsius, included 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 established the Copenhagen Green Climate Fund to support mitigation, adaptation, and other climate-related activities in developing countries. Once 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.

On September 21, 2009, the U.S. Court of Appeals for the Second Circuit and on October 16, 2009, 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. While FirstEnergy is not a party to this litigation, should the court of appeals decision be affirmed or not subjected to further review, FirstEnergy and/or one or more of its subsidiaries could be named in actions making similar allegations.

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 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, Ohio, New Jersey and Pennsylvania have water quality standards applicable to FirstEnergy s operations.

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). 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. On April 1, 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. The EPA is developing a new regulation under Section 316(b) of the Clean Water Act consistent with the opinions of the Supreme Court and the Court of Appeals which have created significant uncertainty about the specific nature, scope and timing of the final performance standard. 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. On March 15, 2010, the EPA issued a draft permit for the Bay Shore power 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 June 2008, the U.S. Attorney s Office in Cleveland, Ohio advised FGCO that it is 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. FGCO is unable to predict the outcome of this matter.

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.

On December 30, 2009, in an advanced notice of public rulemaking, the EPA said that the large volumes of coal combustion residuals produced by electric utilities pose significant financial risk to the industry. On May 4, 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. FGCO s future cost of compliance with any coal combustion residuals regulations which 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.

The Utilities 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 June 30, 2010, based on estimates of the total costs of cleanup, the Utilities proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $105 million (JCP&L $76 million, TE - $1 million, CEI $1 million, FGCO $1 million and FirstEnergy $26 million) have been accrued through June 30, 2010. Included in the total are accrued liabilities of approximately $67 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.

(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 s territory. 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.

Early in 2010, the Appellate Division heard oral argument on plaintiff s appeal of the trial court s decision decertifying the class, and on July 29, 2010, the Appellate Division upheld the trial court s decision.

Litigation Relating to the Proposed Allegheny Energy Merger

In connection with the proposed merger (Note 15), purported shareholders of Allegheny Energy have filed putative shareholder class action and/or derivative lawsuits in Pennsylvania and Maryland state courts, as well as in the U.S. District Court for the Western District of Pennsylvania, against Allegheny Energy and its directors and certain officers, referred to as the Allegheny Energy defendants, FirstEnergy and Merger Sub. In summary, the lawsuits allege, among other things, that the Allegheny Energy directors breached their fiduciary duties by approving the merger agreement, and that Allegheny Energy, FirstEnergy and Merger Sub aided and abetted in these alleged breaches of fiduciary duty. The complaints seek, among other things, jury trials, money damages and injunctive relief. Additional details about the actions are provided below. While FirstEnergy believes the lawsuits are without merit and has defended vigorously against the claims, in order to avoid the costs associated with the litigation, the defendants have agreed to the terms of a disclosure-based settlement of the lawsuits. The defendants reached an agreement with counsel for all of the plaintiffs concerning fee applications, but a formal stipulation of settlement has not yet been filed with any court. If the parties are unable to obtain final approval of the settlement, then litigation will proceed, and the outcome of any such litigation is inherently uncertain. If a dismissal is not granted or a settlement is not reached, these lawsuits could prevent or delay the completion of the merger and result in substantial costs to FirstEnergy. The defense or settlement of any lawsuit or claim that remains unresolved at the time the merger closes may adversely affect FirstEnergy s business, financial condition or results of operations.

Four putative class action and derivative lawsuits were filed in the Circuit Court for Baltimore City, Maryland. One was withdrawn. The court consolidated the three cases under the caption *Oakmont Capital Management, LLC v. Evanson, et al.*, C.A. No. 24-C-10-1301, and appointed Lewis M. Lynn as Lead Plaintiff. Plaintiff Lynn filed a Consolidated Amended Complaint on April 12, 2010. On April 21, 2010, defendants filed Motions to Dismiss the Consolidated Amended Complaint for failure to state a claim. The court has stayed all discovery pending resolution of those motions. The court also has entered a stipulated order certifying a class with no opt-out rights. On May 27, 2010, the parties reported to the court that they have agreed to the terms of a disclosure-based settlement and requested that the court cancel the oral argument on the motions to dismiss that had been scheduled for June 3, 2010. On May 28, 2010, the court removed the hearing from its calendar.

Three shareholder lawsuits were filed in the Court of Common Pleas of Westmoreland County, Pennsylvania, raising putative class action and derivative claims against the Allegheny Energy directors and officers, FirstEnergy and Allegheny Energy. The court has consolidated these actions under the caption, *In re Allegheny Energy, Inc. Shareholder Class and Derivative, Litigation*, Lead Case No. 1101 of 2010, and appointed lead counsel. On April 5, 2010, the Allegheny Energy defendants filed a Motion to Stay the Proceedings. Shortly thereafter, FirstEnergy similarly filed a Motion to Stay. Plaintiffs filed a Motion for Expedited Discovery. The court scheduled a hearing on the motions for May 27, 2010. On May 21, 2010, plaintiffs filed a Verified Consolidated Shareholder Derivative and Class Complaint. On May 26, 2010, the parties filed a Motion for a Continuance of the May 27 hearing, which the court granted. On June 1, 2010, the parties reported to the court that they have agreed to the terms of a disclosure-based settlement.

A putative shareholder lawsuit styled as a class action was filed in the U.S. District Court for the Western District of Pennsylvania and is captioned *Louisiana Municipal Police Employees Retirement System v. Evanson, et al.*, C.A. No. 10-319 NBF. On June 1, 2010, the parties reported to the court that they have agreed to the terms of a disclosure-based settlement.

Nuclear Plant Matters

During a planned refueling outage that began on February 28, 2010, FENOC conducted a non destructive examination and testing of the Control Rod Drive Mechanism (CRDM) Nozzles of the Davis-Besse reactor pressure vessel head. FENOC identified flaws in CRDM nozzles that required modification. The NRC was notified of these findings, along with federal, state and local officials. On March 17, 2010, the NRC sent a special inspection team to Davis-Besse to assess the adequacy of FENOC s identification, analyses and resolution of the CRDM nozzle flaws and to ensure acceptable modifications were made prior to placing the RPV head back in service. After successfully completing the modifications, FENOC committed to take a number of corrective actions including strengthening leakage monitoring procedures and shutting Davis-Besse down no later than October 1, 2011, to replace the reactor pressure vessel head with nozzles made of material less susceptible to primary water stress corrosion cracking further enhancing the safe and reliable operations of the plant. On June 29, 2010, FENOC returned Davis-Besse to service.

On April 5, 2010, the Union of Concerned Scientists (UCS) requested that the NRC issue a Show Cause Order, or otherwise delay the restart of the Davis-Besse Nuclear Power Station until the NRC determines that adequate protection standards have been met and reasonable assurance exists that these standards will continue to be met after the plant s operation is resumed. By a letter dated July 13, 2010, the NRC denied UCS s request for immediate action because the NRC has conducted rigorous and independent assessments of returning the Davis-Besse reactor vessel head to service and its continued operation, and determined that it was safe for the plant to restart. The UCS petition was referred to a petition manager for further review. What additional actions, if any that the NRC takes in response to the UCS request, have not been determined.

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of obligations. As of June 30, 2010, FirstEnergy had approximately $1.9 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. As part of the application to the NRC to transfer the ownership of Davis-Besse, Beaver Valley and Perry to NGC in 2005, FirstEnergy provided an additional $80 million parental guarantee associated with the funding of decommissioning costs for these units and indicated that it planned to contribute an additional $80 million to these trusts by 2010. By a letter dated March 8, 2010, primarily as a result of the Beaver Valley Power Station operating license renewal, FENOC requested that the NRC reduce FirstEnergy s parental guarantee to $15 million and notified the staff that it no longer planned to make the additional contributions into the trusts. By a letter dated July 14, 2010, the NRC stated that it had no objection to the reduction in the parental guarantee.

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Other Legal Matters

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy s normal business operations pending against FirstEnergy and its subsidiaries. The other potentially material items not otherwise discussed above are described below.

On April 14, 2010, JCP&L reached an agreement on a settlement package with its bargaining unit employees regarding a grievance challenging JCP&L s 2002 call-out procedure that required bargaining unit employees to respond to emergency power outages. The agreement included an agreed-upon settlement amount and extension of the collective bargaining agreement. On July 22, 2010, the court signed an order approving and implementing the parties agreement. As of June 30, 2010, JCP&L reduced its reserve to $9 million for the settlement which will be paid to the employees over the next thirty days beginning on July 25, 2010. The collective bargaining agreement extension is also effective as of July 25, 2010.

On February 16, 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. On March 18, 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 has not yet ruled on that motion to dismiss. The named-defendant companies will continue to defend these claims including challenging any class certification.

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. If it were ultimately determined that FirstEnergy or its subsidiaries have legal liability or are otherwise made subject to liability based on the above matters, it could have a material adverse effect on FirstEnergy s or its subsidiaries financial condition, results of operations and cash flows.

9. REGULATORY MATTERS

(A) RELIABILITY INITIATIVES

Federally-enforceable mandatory reliability standards apply to the bulk power system and impose certain operating, record-keeping and reporting requirements on the Utilities and ATSI. The NERC has delegated day-to-day implementation and enforcement of these reliability standards to eight regional entities, including Reliability*First* Corporation. All of FirstEnergy s facilities are located within the Reliability*First* region. FirstEnergy actively participates in the NERC and Reliability*First* 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 Reliability*First* Corporation.

FirstEnergy believes that it is in compliance with all currently-effective and enforceable reliability standards. Nevertheless, FirstEnergy also believes that the NERC, Reliability*First* and the FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. The financial impact of complying with 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 new reliability standards be recovered in rates. Still, 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.

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(B) OHIO

The Ohio Companies operate under an Amended ESP, which expires on May 31, 2011, and provides for generation supplied through a CBP. The Amended ESP also allows the Ohio Companies to collect a delivery service improvement rider (Rider DSI) at an overall average rate of $0.002 per KWH for the period of April 1, 2009 through December 31, 2011. The Ohio Companies currently purchase generation at the average wholesale rate of a CBP conducted in May 2009. FES is one of the suppliers to the Ohio Companies through the CBP. The PUCO approved a $136.6 million distribution rate increase for the Ohio Companies in January 2009, which went into effect on January 23, 2009 for OE ($68.9 million) and TE ($38.5 million) and on May 1, 2009 for CEI ($29.2 million). As one element of the Amended ESP, the Ohio Companies agreed not to seek an additional base distribution rate increase, subject to certain exceptions, that would be effective before January 1, 2012. Applications for rehearing of the PUCO order in the distribution case were filed by the Ohio Companies and one other party. The Ohio Companies raised numerous issues in their application for rehearing related to rate recovery of certain expenses, recovery of line extension costs, the level of rate of return and the amount of general plant balances. The PUCO has not yet issued a substantive Entry on Rehearing.

On October 20, 2009, the Ohio Companies filed an MRO to procure, through a CBP, generation supply for customers who do not shop with an alternative supplier for the period beginning June 1, 2011. The CBP would be similar, in all material respects, to the CBP conducted in May 2009 in that it would procure energy, capacity and certain transmission services on a slice of system basis. However, unlike the May 2009 CBP, the MRO would include multiple bidding sessions and multiple products with different delivery periods for generation supply designed to reduce potential volatility and supplier risk and encourage bidder participation. A technical conference and hearings were held in 2009 and the matter has been fully briefed. Pursuant to SB221, the PUCO has 90 days from the date of the application to determine whether the MRO meets certain statutory requirements. Although the Ohio Companies requested a PUCO determination by January 18, 2010, on February 3, 2010, the PUCO announced that its determination would be delayed. Under a determination that such statutory requirements are met, and to the extent the ESP described below has not been implemented, the Ohio Companies would expect to implement the MRO.

On March 23, 2010, the Ohio Companies filed an application for a new ESP, which if approved by the PUCO, would go into effect on June 1, 2011 and conclude on May 31, 2014. Attached to the application was a Stipulation and Recommendation signed by the Ohio Companies, the Staff of the PUCO, and an additional fourteen parties signing as Signatory Parties, with two additional parties agreeing not to oppose the adoption of the Stipulation. The material terms of the Stipulation include a CBP similar to the one used in May 2009 and the one proposed in the October 2009 MRO filing; a 6% generation discount to certain low-income customers provided by the Ohio Companies through a bilateral wholesale contract with FES; no increase in base distribution rates through May 31, 2014; and a new distribution rider, Delivery Capital Recovery Rider (Rider DCR), to recover a return of, and on, capital investments in the delivery system. This Rider substitutes for Rider DSI which terminates by its own terms. The Ohio Companies also agree not to collect certain amounts associated with RTEP and administrative costs associated with the move to PJM. Many of the existing riders approved in the previous ESP remain in effect, some with modifications. The new ESP also requests the resolution of current proceedings pending at the PUCO regarding corporate separation, elements of the smart grid proceeding and the move to PJM. The evidentiary hearing began on April 20, 2010, at the PUCO. The Stipulation requested a decision by the PUCO by May 5, 2010. On April 28, 2010, the PUCO Chairman issued a statement that the PUCO would not issue a decision on May 5, 2010, and would take additional time to review the case record. FirstEnergy recorded approximately $39.5 million of regulatory asset impairments and expenses related to the ESP. On May 12, 2010 a supplemental stipulation was filed that added two additional parties to the Stipulation, namely the City of Akron, Ohio and Council for Smaller Enterprises, to provide additional energy efficiency benefits. Pursuant to a PUCO Entry, a hearing was held on June 21, 2010 to consider the estimated bill impacts arising from the proposed ESP, and testimony was provided in support of the supplemental stipulation. On July 22, 2010, a second supplemental stipulation was filed that, among other provisions and if approved, would provide a commitment that retail customers of the Ohio Companies will not pay certain costs related to the companies integration into PJM, a regional transmission organization, for the longer of the five year period from June 1, 2011 through May 31, 2016 or when the amount of costs avoided by customers for certain types of products totals $360 million, and establishes a

$12 million fund to assist low income customers over the term of the ESP. Additional parties signing or not opposing the second supplemental stipulation include Northeast Ohio Public Energy Council (NOPEC), Northwest Ohio Aggregation Coalition (NOAC), Environmental Law and Policy Center and a number of low income community agencies. A hearing was held on the second supplemental stipulation on July 29, 2010. The matter is awaiting decision from the PUCO**.**

Under the provisions of SB221, the Ohio Companies are required to implement energy efficiency programs that will achieve a total annual energy savings equivalent of approximately 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 are also required to reduce peak demand in 2009 by 1%, with an additional 0.75% reduction each year thereafter through 2018. The PUCO may amend these benchmarks in certain, limited circumstances, and the Ohio Companies filed an application with the PUCO seeking such amendments. On January 7, 2010, the PUCO amended the Ohio Companies 2009 energy efficiency benchmarks to zero, contingent upon the Ohio Companies meeting the revised benchmarks in a period of not more than three years. On March 10, 2010, the PUCO found that the Ohio Companies peak demand reduction programs complied with PUCO rules.

On December 15, 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. On March 8, 2010, the Ohio Companies filed their 2009 Status Update Report with the PUCO in which they indicated compliance with the 2009 statutory energy efficiency and peak demand benchmarks as those benchmarks were amended as described above. The Ohio Companies expect that all costs associated with compliance will be recoverable from customers. The Ohio Companies three year portfolio plan is still awaiting decision from the PUCO. The plan has yet to be approved by the PUCO, which is delaying the launch of the programs described in the plan. Without such approval, the Ohio Companies compliance with 2010 benchmarks is jeopardized and if not approved soon may require the Ohio Companies to seek an amendment to their annual benchmark requirements for 2010. Failure to comply with the benchmarks or to obtain such an amendment may subject the Companies to an assessment by the PUCO of a forfeiture.

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 serve in 2009. In August and October 2009, the Ohio Companies conducted RFPs to secure RECs. The RFPs sought RECs, including solar RECs and RECs generated in Ohio in order to meet the Ohio Companies alternative energy requirements as set forth in SB221 for 2009, 2010 and 2011. The RECs acquired through these two RFPs will be used to help meet the renewable energy requirements established under SB221 for 2009, 2010 and 2011. On March 10, 2010, the PUCO found that there was an insufficient quantity of solar energy resources reasonably available in the market. The PUCO reduced the Ohio Companies aggregate 2009 benchmark to the level of solar RECs the Ohio Companies acquired through their 2009 RFP processes, provided the Companies 2010 alternative energy requirements be increased to include the shortfall for the 2009 solar REC benchmark. On April 15, 2010, the Ohio Companies and FES (due to its status as an electric service company in Ohio) filed compliance reports with the PUCO setting forth how they individually satisfied the alternative energy requirements in SB221 for 2009. FES also applied for a force majeure determination from the PUCO regarding a portion of their compliance with the 2009 solar energy resource benchmark, which application is still pending. On July 1, 2010, the Ohio Companies announced their intent to conduct an RFP in 2010 to secure RECs and solar RECs needed to meet the Ohio Companies alternative energy requirements as set forth in SB221. RFP bids are due August 3, 2010 and contracts are expected to be signed the week of August 9, 2010.

On February 12, 2010, OE and CEI filed an application with the PUCO to establish a new credit for all-electric customers. On March 3, 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 on March 17, 2010. On April 15, 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 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 on May 21, 2010. The Ohio Companies also filed on May 14, 2010 an application for rehearing of the Second Entry on Rehearing, which was granted for purposes of further consideration on June 9, 2010. No hearing has been scheduled in this matter.

As noted above in Note 8, FirstEnergy, CEI and OE filed a motion to dismiss a class action lawsuit related to the PUCO approved reduction of a discount that had previously been in place for residential customers with electric heating, electric water heating, or load management systems. The court has not yet ruled on that motion to dismiss.

(C) PENNSYLVANIA

Met-Ed and Penelec purchase a portion of their POLR and default service requirements from FES through a fixed-price partial requirements wholesale power sales agreement. The agreement allows Met-Ed and Penelec to sell the output of NUG energy to the market and requires FES to provide energy at fixed prices to replace any NUG energy sold to the extent needed for Met-Ed and Penelec to satisfy their POLR and default service obligations.

Met-Ed and Penelec filed with the PPUC a generation procurement plan covering the period January 1, 2011 through May 31, 2013. The plan is designed to provide adequate and reliable service via a prudent mix of long-term, short-term and spot market generation supply, as required by Act 129, with a staggered procurement schedule, which varies by customer class, through the use of a descending clock auction. On August 12, 2009, Met-Ed and Penelec filed a settlement agreement with the PPUC for the generation procurement plan, reflecting the settlement on all but two reserved issues. On November 6, 2009, the PPUC entered an Order approving the settlement and finding in favor of Met-Ed and Penelec on the two reserved issues. Generation procurement began in January 2010.

On February 8, 2010, Penn filed a Petition for Approval of its Default Service Plan for the period June 1, 2011 through May 31, 2013. The parties to the proceeding have reached a settlement on all issues and filed a joint petition to approve the settlement agreement in July 2010. The PPUC is required to issue an order on the plan no later than November 8, 2010. If approved, procurement under the plan is expected to begin January 2011.

The PPUC adopted a Motion on January 28, 2010 and subsequently entered an Order on March 3, 2010 which denies the recovery of marginal transmission losses through the TSC rider for the period of June 1, 2007 through March 31, 2008, and directs Met-Ed and Penelec to submit a new tariff or tariff supplement reflecting the removal of marginal transmission losses from the TSC, and instructs 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. On March 18, 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 marginal transmission loss costs. By Order entered March 25, 2010, the PPUC granted the requested stay until December 31, 2010. Pursuant to the PPUC s order, Met-Ed and Penelec filed the plan to establish separate accounts for marginal transmission loss revenues and related interest and carrying charges and the plan for the use of these funds to mitigate future generation rate increases commencing January 1, 2011. The PPUC approved this plan June 7, 2010. On April 1, 2010, Met-Ed and Penelec filed a Petition for Review with the Commonwealth Court of Pennsylvania appealing the PPUC s March 3, 2010 Order. Although the ultimate outcome of this matter cannot be determined at this time, it is the belief of Met-Ed and Penelec that they should prevail in the appeal and therefore expect to fully recover the approximately $199.7 million ($158.5 million for Met-Ed and $41.2 million for Penelec) in marginal transmission losses for the period prior to January 1, 2011. On April 2, 2010, Met-Ed and Penelec filed a Response to the PPUC s March 3, 2010 Order requesting approval of procedures to establish separate accounts to track all marginal transmission loss revenues and related interest and the use of those funds to mitigate future generation rate increases commencing January 1, 2011, and the PPUC entered an Order on June 7, 2010, granting Met-Ed s and Penelec s request. On July 9 2010, Met-Ed and Penelec filed their briefs with the Commonwealth Court of Pennsylvania. The Office of Small Business Advocate filed its brief on July 9, 2010. The PPUC s brief is due to be filed in August 2010. On May 20, 2010, the PPUC approved Met-Ed s and Penelec s annual updates to their TSC rider for the period June 1, 2010 through 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 TSC for Met-Ed s customers increased to be fully recovered by December 31, 2010.

Act 129 was enacted 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. The PPUC entered an Order on February 26, 2010 approving the Pennsylvania Companies EE&C Plans and the tariff rider with rates effective March 1, 2010.

Met-Ed, Penelec and Penn jointly filed a Smart Meter Technology Procurement and Installation Plan with the PPUC. This plan proposes a 24-month assessment period in which the Pennsylvania Companies 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 at approximately $29.5 million, which the Pennsylvania Companies, in their plan, proposed to recover through an automatic adjustment clause. The ALJ s Initial Decision approved the Smart Meter Plan as modified by the ALJ, including: ensuring that the smart meters to be deployed include the capabilities listed in the PPUC s Implementation Order; eliminating the provision of interest in the 1307(e) reconciliation; providing for the recovery of reasonable and prudent costs minus resulting savings from installation and use of smart meters; and reflecting that administrative start-up costs be expensed and the costs incurred for research and development in the assessment period be capitalized. On April 15, 2010, the PPUC adopted a Motion by Chairman Cawley that modified the ALJ s initial decision, and decided various issues regarding the Smart Meter Implementation Plan for the Pennsylvania Companies. The PPUC entered its Order on June 9, 2010, consistent with the Chairman s Motion. On June 24, 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 roll smart meter costs into base rates.

Legislation addressing rate mitigation and the expiration of rate caps was introduced in the legislative session that ended in 2008; several bills addressing these issues were introduced in the 2009 legislative session. The final form and impact of such legislation is uncertain.

By Tentative Order entered September 17, 2009, the PPUC provided for an additional 30-day comment period on whether the 1998 Restructuring Settlement 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 above accounting method utilized by Met-Ed and Penelec. Met-Ed and Penelec are awaiting further action by the PPUC.

(D) NEW JERSEY

JCP&L is permitted to defer for future collection from customers the amounts by which its costs of supplying BGS to non-shopping customers, costs incurred under NUG agreements, and certain other stranded costs, exceed amounts collected through BGS and NUGC rates and market sales of NUG energy and capacity. As of June 30, 2010, the accumulated deferred cost balance totaled approximately $81 million. To better align the recovery of expected costs, on July 26, 2010, JCP&L filed a request to decrease the amount recovered for the costs incurred under the NUG agreements by $180 million annually. If approved as filed, the change would not go into effect until January 1, 2011.

In accordance with an April 28, 2004 NJBPU order, JCP&L filed testimony on June 7, 2004, supporting continuation of the current level and duration of the funding of TMI-2 decommissioning costs by New Jersey customers without a reduction, termination or capping of the funding. On September 30, 2004, JCP&L filed an updated TMI-2 decommissioning study. This study resulted in an updated total decommissioning cost estimate of $729 million (in 2003 dollars) compared to the estimated $528 million (in 2003 dollars) from the prior 1995 decommissioning study. The DPA filed comments on February 28, 2005 requesting that decommissioning funding be suspended. On March 18, 2005, JCP&L filed a response to those comments. JCP&L responded to additional NJBPU staff discovery requests in May and November 2007 and also submitted comments in the proceeding in November 2007. A schedule for further NJBPU proceedings has not yet been set. On March 13, 2009, JCP&L filed its annual SBC Petition with the NJBPU that includes a request for a reduction in the level of recovery of TMI-2 decommissioning costs based on an updated TMI-2 decommissioning cost analysis dated January 2009 estimated at $736 million (in 2003 dollars). This matter is currently pending before the NJBPU.

New Jersey statutes require that the state periodically undertake a planning process, known as the EMP, to address energy related issues including energy security, economic growth, and environmental impact. The NJBPU adopted an order establishing the general process and contents of specific EMP plans that must be filed by New Jersey electric and gas utilities in order to achieve the goals of the EMP. On April 16, 2010, the NJBPU issued an order indefinitely suspending the requirement of New Jersey utilities to submit Utility Master Plans until such time as the status of the EMP has been made clear. At this time, FirstEnergy and JCP&L cannot determine the impact, if any, the EMP may have on their operations.

In support of former New Jersey Governor Corzine s Economic Assistance and Recovery Plan, JCP&L announced a proposal to spend approximately $98 million on infrastructure and energy efficiency projects in 2009. Under the proposal, an estimated $40 million would be spent on infrastructure projects, including substation upgrades, new transformers, distribution line re-closers and automated breaker operations. In addition, approximately $34 million would be spent implementing new demand response programs as well as expanding on existing programs. Another $11 million would be spent on energy efficiency, specifically replacing transformers and capacitor control systems and installing new LED street lights. The remaining $13 million would be spent on energy efficiency programs that would complement those currently being offered. The project relating to expansion of the existing demand response programs was approved by the NJBPU on August 19, 2009, and implementation began in 2009. Approval for the project related to energy efficiency programs intended to complement those currently being offered was denied by the NJBPU on December 1, 2009. On July 6, 2010, the January 30, 2009 petition directed to infrastructure investment which had been pending before the NJBPU was withdrawn by JCP&L. Implementation of the remaining projects is dependent upon resolution of regulatory issues including recovery of the costs associated with the proposal.

(E) FERC MATTERS

PJM Transmission Rate

On April 19, 2007, the 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, the 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, referred to as DFAX , generally referred to as a beneficiary pays approach to allocating the cost of high voltage transmission facilities. The FERC found that PJM s current beneficiary-pays cost allocation methodology was not sufficiently detailed and, in a related order that also was issued on April 19, 2007, directed that hearings be held for the purpose of establishing a just and reasonable cost allocation methodology for inclusion in PJM s tariff. FERC ultimately issued an order approving use of the beneficiary pays method of cost allocation for transmission facilities included in the PJM regional plan that operate below 500 kV.

The FERC s April 19, 2007 order was appealed to the U.S. Court of Appeals for the Seventh Circuit, which issued a decision on August 6, 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 facilities on a load ratio share basis and, based on this finding, remanded the rate design issue back to FERC.

In an order dated January 21, 2010, FERC set the matter for paper hearings meaning that FERC called for parties to submit comments or written testimony 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 within 45 days, and reply comments 30 days later. 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 eastern utilities in PJM bearing the majority of their 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. Certain eastern utilities and their state commissions supported continued socialization of these costs on a load ratio share basis. FERC is not expected to act before the fourth quarter of 2010.

RTO Consolidation

FERC issued an order approving, subject to certain future compliance filings, ATSI s move to PJM. This allows FirstEnergy to consolidate its transmission assets and operations into PJM. Currently, FirstEnergy s transmission assets and operations are divided between PJM and MISO. The consolidation will make the transmission assets that are part of ATSI, whose footprint includes the Ohio Companies and Penn, part of PJM. Most of FirstEnergy s transmission assets in Pennsylvania and all of the transmission assets in New Jersey already operate as a part of PJM. FERC approved FirstEnergy s proposal to use a Fixed Resource Requirement Plan (FRR Plan) to obtain capacity to satisfy the PJM capacity requirements for the 2011-12 and 2012-13 delivery years.

In December 2009, ATSI executed the PJM Consolidated Transmission Owners Agreement and the Ohio Companies and Penn executed the PJM Operating Agreement and the PJM Reliability Assurance Agreement. Execution of these agreements committed ATSI and the Ohio Companies and Penn s load to moving into PJM on the schedule described in the application and approved in the FERC Order.

FirstEnergy successfully conducted the FRR auctions on March 19, and participated in the PJM base residual auction for the 2013 delivery year, thereby obtaining the capacity necessary for its ATSI footprint to meet PJM s capacity requirements. FirstEnergy expects to integrate into PJM effective June 1, 2011.

On September 4, 2009, the PUCO opened a case to take comments from Ohio s stakeholders regarding the RTO consolidation. Several parties have intervened in the regulatory dockets at the FERC and at the PUCO. Certain interveners have commented and protested particular elements of the proposed RTO consolidation, including an exit fee to MISO, integration costs to PJM, and cost-allocations of future transmission upgrades in PJM and MISO.

MISO Complaints Versus PJM

On March 9, 2010, MISO filed two complaints against PJM with FERC under Sections 206, 306 and 309 of the FPA alleging violations of the MISO/PJM Joint Operating Agreement (JOA). In Docket EL 10-46-000, the complaint alleges that PJM erroneously calculated charges to MISO for market-to-market settlements made from 2005 to 2009 pursuant to the congestion management provisions of the JOA. The MISO seeks approximately $130 million plus interest to correct for resultant net underpayments from PJM to MISO. In Docket No.EL10-45-000, MISO alleges that by failing to account for the market flows from 34 PJM generators over the period from 2007-2009, PJM underpaid MISO by a total of roughly $75 million including interest. For the period from 2005-2007, MISO claimed an underpayment by PJM of at least $12 million plus interest. MISO also claimed that PJM failed to maintain required records necessary to calculate underbilling for the 2005-2007 billing.

In the second complaint, MISO alleged that PJM has refused to comply with provisions of the JOA requiring market-to-market dispatch since 2009, and is improperly demanding repayment of redispatch payments previously made to MISO. PJM filed its answers to the complaints on April 12, 2010, opposing the relief sought by MISO.

In addition, on April 12, 2010, PJM filed a complaint with FERC pursuant to Section 206, 306, and 309 alleging that MISO is violating the JOA with PJM by initiating market-to-market coordination and financial settlements for substitute (proxy) reciprocal coordinated flowgates between MISO and PJM. PJM claims that the JOA does not permit MISO to initiate market-to-market settlements using proxy flowgates in lieu of designated reciprocal coordinated flowgates. This complaint addresses substantially the same issues as the second MISO complaint, in which MISO argues that the use of proxy flowgates is permitted by agreement of the RTOs and operating practice. Each party filed a complaint in order to ensure their right to claim refunds, if any, if successful in their arguments at FERC.

On June 29, 2010, FERC issued an order consolidating the cases and establishing settlement judge procedures. If the settlement process is unsuccessful, the cases will proceed to evidentiary hearings. FirstEnergy is unable to predict the outcome of this matter.

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MISO Multi-Value Project Rule Proposal

On July 15, 2010, MISO and certain MISO transmission owners jointly filed with the FERC their proposed cost allocation methodology for new transmission projects. If approved, so-called Multi Value Projects (MVPs) transmission projects that have a regional impact and are part of a regional plan will have a 100% regional allocation of costs under the proposed methodology. If approved by FERC, MISO s proposal is expected to permit the allocation of the costs of large transmission projects designed to integrate wind from the upper Midwest across the entire MISO. MISO has requested a FERC response to the filing by the FERC s December open meeting, but an effective date for its proposal of July 16, 2011. 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.

10. NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

In 2010, the FASB amended the Derivatives and Hedging Topic of the FASB Accounting Standards Codification to clarify the scope exception for embedded credit derivative features related to the transfer of credit risk in the form of subordination of one financial instrument to another. The amendment addresses how to determine which embedded credit derivative features, including those in collateralized debt obligations and synthetic collateralized debt obligations, are considered to be embedded derivatives that should not be analyzed under the Derivatives and Hedging Topic for potential bifurcation and separate accounting. The amendment is effective for the first fiscal quarter beginning after June 15, 2010. FirstEnergy does not expect this standard to have a material effect on its financial statements.

11. SEGMENT INFORMATION

Financial information for each of FirstEnergy s reportable segments is presented in the following table. FES and the Utilities do not have separate reportable operating segments. With the completion of transition to a fully competitive generation market in Ohio in the fourth quarter of 2009, the former Ohio Transitional Generation Services segment was combined with the Energy Delivery Services segment, consistent with how management views the business. Disclosures for FirstEnergy s operating segments for 2009 have been reclassified to conform to the current presentation.

The Energy Delivery Services segment transmits and distributes electricity through FirstEnergy s eight utility operating companies, serving 4.5 million customers within 36,100 square miles of Ohio, Pennsylvania and New Jersey and purchases power for its POLR and default service requirements in Ohio, Pennsylvania and New Jersey. Its 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 (default service) in its Ohio, Pennsylvania and New Jersey franchise areas. Its results reflect the commodity costs of securing electric generation from FES and from non-affiliated power suppliers, the net PJM and MISO transmission expenses related to the delivery of the respective generation loads, and the deferral and amortization of certain fuel costs.

The Competitive Energy Services segment supplies electric power to end-use customers through retail and wholesale arrangements, including associated company power sales to meet all or 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, Maryland and Michigan. This business segment owns or leases and operates 19 generating facilities with a net demonstrated capacity of 13,710 MWs and also purchases electricity to meet sales obligations. The segment s net income is primarily derived from affiliated and non-affiliated electric generation sales revenues less the related costs of electricity generation, including purchased power and net transmission (including congestion) and ancillary costs charged by PJM and MISO to deliver energy to the segment s customers.

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

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Segment Financial Information	Energy Delivery Services	Competitive Energy Services	Other (In millions)	Reconciling Adjustments	Consolidated
Three Months Ended					
June 30, 2010					
External revenues	$ 2,373	$ 778	$ 6	$ (29)	$ 3,128
Internal revenues	19	539		(558)	
Total revenues	2,392	1,317	6	(587)	3,128
Depreciation and amortization	276	66	6	3	351
Investment income (loss), net	27	13		(9)	31
Net interest charges	123	31	3	10	167
Income taxes	89	76	(22)	(9)	134
Net income (loss)	143	125	16	(28)	256
Total assets	22,450	11,100	591	325	34,466
Total goodwill	5,551	24			5,575
Property additions	172	282	7	28	489
June 30, 2009					
External revenues	$ 2,792	$ 504	$ 5	$ (30)	$ 3,271
Internal revenues		839		(839)	
Total revenues	2,792	1,343	5	(869)	3,271
Depreciation and amortization	298	68	3	4	373
Investment income (loss), net	35	6		(14)	27
Net interest charges	113	18	2	40	173
Income taxes	103	185	(20)	(20)	248
Net income	154	276	18	(40)	408
Total assets	23,215	10,144	684	263	34,306
Total goodwill	5,551	24			5,575
Property additions	178	248	70	(7)	489
Six Months Ended					
June 30, 2010					
External revenues	$ 4,916	$ 1,494	$ 10	$ (60)	$ 6,360
Internal revenues*	19	1,213		(1,165)	67
Total revenues	4,935	2,707	10	(1,225)	6,427
Depreciation and amortization	601	132	19	4	756
Investment income (loss), net	52	14		(19)	47
Net interest charges	246	64	2	27	339
Income taxes	158	123	(18)	(18)	245
Net income (loss)	257	201	1	(54)	405
Total assets	22,450	11,100	591	325	34,466

Total goodwill		5,551		24						5,575
Property additions		338		605		10		44		997
June 30, 2009										
External revenues	$	5,813	$	839	$	12	$	(59)	$	6,605
Internal revenues				1,732				(1,732)		
Total revenues		5,813		2,571		12		(1,791)		6,605
Depreciation and amortization		725		132		4		7		868
Investment income (loss), net		65		(23)				(26)		16
Net interest charges		222		36		3		78		339
Income taxes		91		288		(37)		(40)		302
Net income		136		431		35		(79)		523
Total assets		23,215		10,144		684		263		34,306
Total goodwill		5,551		24						5,575
Property additions		343		669		119		12		1,143

* Under the accounting standard for the effects of certain types of regulation, internal revenues are not fully offset for sales of RECs by FES to the Ohio Companies that are retained in inventory.

Reconciling adjustments to segment operating results from internal management reporting to consolidated external financial reporting primarily consist of interest expense related to holding company debt, corporate support services revenues and expenses and elimination of intersegment transactions.

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12. SUPPLEMENTAL GUARANTOR INFORMATION

On July 13, 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 month and six month periods ended June 30, 2010 and 2009, consolidating balance sheets as of June 30, 2010 and December 31, 2009 and consolidating statements of cash flows for the six months ended June 30, 2010 and 2009 for FES (parent and guarantor), FGCO and NGC (non-guarantor) are presented below. Investments in wholly owned subsidiaries are accounted for by FES using the equity method. Results of operations for FGCO and NGC are, therefore, reflected in FES investment accounts and earnings as if operating lease treatment was achieved. The principal elimination entries eliminate investments in subsidiaries and intercompany balances and transactions and the entries required to reflect operating lease treatment associated with the 2007 Bruce Mansfield Unit 1 sale and leaseback transaction.

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF INCOME
(Unaudited)

For the Three Months Ended June 30, 2010	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
REVENUES	$ 1,295,700	$ 580,621	$ 338,933	$ (900,580)	$ 1,314,674
EXPENSES:					
Fuel	7,268	300,867	34,276		342,411
Purchased power from affiliates	912,858	7,163	49,457	(900,580)	68,898
Purchased power from non-affiliates	298,820				298,820
Other operating expenses	80,983	94,373	116,350	12,189	303,895
Provision for depreciation	711	27,466	36,449	(1,307)	63,319
General taxes	5,718	9,227	7,327		22,272
Total expenses	1,306,358	439,096	243,859	(889,698)	1,099,615
OPERATING INCOME (LOSS)	(10,658)	141,525	95,074	(10,882)	215,059
OTHER INCOME (EXPENSE):					
Investment income	1,811	81	11,474		13,366
Miscellaneous income (expense), including net income from equity investees	151,291	709	102	(147,709)	4,393
Interest expense to affiliates	(61)	(2,084)	(415)		(2,560)
Interest expense other	(24,262)	(27,799)	(15,361)	16,050	(51,372)
Capitalized interest	98	19,573	4,234		23,905
Total other income (expense)	128,877	(9,520)	34	(131,659)	(12,268)
INCOME BEFORE INCOME TAXES	118,219	132,005	95,108	(142,541)	202,791
INCOME TAXES (BENEFITS)	(15,706)	48,465	33,550	2,557	68,866
NET INCOME	$ 133,925	$ 83,540	$ 61,558	$ (145,098)	$ 133,925

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

For the Six Months Ended June 30, 2010	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
REVENUES	$ 2,662,725	$ 1,148,985	$ 765,253	$ (1,874,196)	$ 2,702,767
EXPENSES:					
Fuel	12,365	581,730	76,537		670,632
Purchased power from affiliates	1,881,395	12,242	110,410	(1,874,196)	129,851
Purchased power from non-affiliates	749,035				749,035
Other operating expenses	134,109	194,149	255,770	24,378	608,406
Provision for depreciation	1,501	53,993	73,359	(2,616)	126,237
General taxes	11,216	23,827	13,975		49,018
Total expenses	2,789,621	865,941	530,051	(1,852,434)	2,333,179
OPERATING INCOME (LOSS)	(126,896)	283,044	235,202	(21,762)	369,588
OTHER INCOME (EXPENSE):					
Investment income	3,708	135	10,240		14,083
Miscellaneous income (expense), including net income from equity investees	317,664	(924)	1	(311,038)	5,703
Interest expense to affiliates	(119)	(3,896)	(850)		(4,865)
Interest expense other	(47,635)	(54,305)	(31,124)	32,048	(101,016)
Capitalized interest	198	35,906	7,491		43,595
Total other income (expense)	273,816	(23,084)	(14,242)	(278,990)	(42,500)
INCOME BEFORE INCOME TAXES	146,920	259,960	220,960	(300,752)	327,088
INCOME TAXES (BENEFITS)	(66,931)	96,508	78,563	5,097	113,237
NET INCOME	$ 213,851	$ 163,452	$ 142,397	$ (305,849)	$ 213,851

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

For the Three Months Ended June 30, 2009	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
REVENUES	$ 1,067,987	$ 703,110	$ 389,695	$ (819,640)	$ 1,341,152
EXPENSES:					
Fuel	5,027	238,832	26,450		270,309
Purchased power from affiliates	814,622	5,018	51,249	(819,640)	51,249
Purchased power from non-affiliates	185,613				185,613
Other operating expenses	35,771	99,145	131,159	12,189	278,264
Provision for depreciation	1,017	30,191	35,654	(1,314)	65,548
General taxes	3,769	11,332	6,184		21,285
Total expenses	1,045,819	384,518	250,696	(808,765)	872,268
OPERATING INCOME	22,168	318,592	138,999	(10,875)	468,884
OTHER INCOME (EXPENSE):					
Investment income	(518)	131	6,030		5,643
Miscellaneous income (expense), including net income from equity investees	289,312	820		(282,510)	7,622
Interest expense to affiliates	(34)	(1,623)	(1,658)		(3,315)
Interest expense other	(2,900)	(24,967)	(14,677)	16,273	(26,271)
Capitalized interest	46	11,126	2,856		14,028
Total other income (expense)	285,906	(14,513)	(7,449)	(266,237)	(2,293)
INCOME BEFORE INCOME TAXES	308,074	304,079	131,550	(277,112)	466,591
INCOME TAXES	10,672	108,114	48,163	2,240	169,189
NET INCOME	$ 297,402	$ 195,965	$ 83,387	$ (279,352)	$ 297,402

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

For the Six Months Ended June 30, 2009	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
REVENUES	$ 2,269,882	$ 1,249,036	$ 785,323	$ (1,736,983)	$ 2,567,258
EXPENSES:					
Fuel	7,122	513,679	55,666		576,467
Purchased power from affiliates	1,729,883	7,100	114,456	(1,736,983)	114,456
Purchased power from non-affiliates	345,955				345,955
Other operating expenses	74,038	203,588	283,615	24,379	585,620
Provision for depreciation	2,036	60,211	67,303	(2,629)	126,921
General taxes	8,475	23,958	12,228		44,661
Total expenses	2,167,509	808,536	533,268	(1,715,233)	1,794,080
OPERATING INCOME	102,373	440,500	252,055	(21,750)	773,178
OTHER INCOME (EXPENSE):					
Investment income	214	162	(23,607)		(23,231)
Miscellaneous income (expense), including net income from equity investees	409,093	742		(399,702)	10,133
Interest expense to affiliates	(68)	(3,381)	(2,845)		(6,294)
Interest expense other	(5,420)	(46,025)	(29,845)	32,492	(48,798)
Capitalized interest	97	18,876	5,133		24,106
Total other income (expense)	403,916	(29,626)	(51,164)	(367,210)	(44,084)
INCOME BEFORE INCOME TAXES	506,289	410,874	200,891	(388,960)	729,094
INCOME TAXES	38,206	147,256	71,092	4,457	261,011
NET INCOME	$ 468,083	$ 263,618	$ 129,799	$ (393,417)	$ 468,083

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

As of June 30, 2010	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$	$ 2	$ 9	$	$ 11
Receivables					
Customers	315,178				315,178
Associated companies	327,070	257,268	89,725	(319,936)	354,127
Other	24,815	6,946	4,631		36,392
Notes receivable from associated companies	84,337		89,594		173,931
Materials and supplies, at average cost	23,804	333,709	221,008		578,521
Prepayments and other	162,845	5,600	4,069		172,514
	938,049	603,525	409,036	(319,936)	1,630,674
PROPERTY, PLANT AND EQUIPMENT:					
In service	93,403	5,588,112	5,203,976	(385,086)	10,500,405
Less Accumulated provision for depreciation	15,742	2,824,150	2,028,479	(173,191)	4,695,180
	77,661	2,763,962	3,175,497	(211,895)	5,805,225
Construction work in progress	7,412	2,149,132	466,321		2,622,865
	85,073	4,913,094	3,641,818	(211,895)	8,428,090
INVESTMENTS:					
Nuclear plant decommissioning trusts			1,107,594		1,107,594
Investment in associated companies	4,790,066			(4,790,066)	
Other	759	7,003	203		7,965
	4,790,825	7,003	1,107,797	(4,790,066)	1,115,559
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income taxes	78,986	340,072		(419,058)	
Customer intangibles	118,219				118,219
Goodwill	24,248				24,248
Property taxes		27,811	22,314		50,125
Unamortized sale and leaseback costs		14,168		63,478	77,646

Other	102,829	76,609	9,655	(60,778)	128,315
	324,282	458,660	31,969	(416,358)	398,553
	$ 6,138,229	$ 5,982,282	$ 5,190,620	$ (5,738,255)	$ 11,572,876
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$ 755	$ 472,357	$ 927,772	$ (19,101)	$ 1,381,783
Short-term borrowings					
Associated companies		85,128			85,128
Other	100,000				100,000
Accounts payable					
Associated companies	311,959	257,889	154,508	(311,849)	412,507
Other	101,776	134,944			236,720
Accrued taxes	1,717	74,125	54,576	(21,336)	109,082
Other	216,207	102,780	15,377	34,722	369,086
	732,414	1,127,223	1,152,233	(317,564)	2,694,306
CAPITALIZATION:					
Common stockholder s equity	3,731,382	2,504,419	2,268,860	(4,773,279)	3,731,382
Long-term debt and other long-term obligations	1,518,968	1,820,112	506,533	(1,259,694)	2,585,919
	5,250,350	4,324,531	2,775,393	(6,032,973)	6,317,301
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction				976,012	976,012
Accumulated deferred income taxes			373,725	(363,730)	9,995
Accumulated deferred investment tax credits		34,820	21,490		56,310
Asset retirement obligations		26,196	837,213		863,409
Retirement benefits	35,830	188,023			223,853
Property taxes		27,811	22,314		50,125
Lease market valuation liability		239,447			239,447
Other	119,635	14,231	8,252		142,118
	155,465	530,528	1,262,994	612,282	2,561,269
	$ 6,138,229	$ 5,982,282	$ 5,190,620	$ (5,738,255)	$ 11,572,876

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FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

As of December 31, 2009	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$	$ 3	$ 9	$	$ 12
Receivables-					
Customers	195,107				195,107
Associated companies	305,298	175,730	134,841	(297,308)	318,561
Other	28,394	10,960	12,518		51,872
Notes receivable from associated companies	416,404	240,836	147,863		805,103
Materials and supplies, at average cost	17,265	307,079	215,197		539,541
Prepayments and other	80,025	18,356	9,401		107,782
	1,042,493	752,964	519,829	(297,308)	2,017,978
PROPERTY, PLANT AND EQUIPMENT:					
In service	90,474	5,478,346	5,174,835	(386,023)	10,357,632
Less Accumulated provision for depreciation	13,649	2,778,320	1,910,701	(171,512)	4,531,158
	76,825	2,700,026	3,264,134	(214,511)	5,826,474
Construction work in progress	6,032	2,049,078	368,336		2,423,446
	82,857	4,749,104	3,632,470	(214,511)	8,249,920
INVESTMENTS:					
Nuclear plant decommissioning trusts			1,088,641		1,088,641
Investment in associated companies	4,477,602			(4,477,602)	
Other	1,137	21,127	202		22,466
	4,478,739	21,127	1,088,843	(4,477,602)	1,111,107
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income taxes	93,379	381,849		(388,602)	86,626
Customer intangibles	16,566				16,566
Goodwill	24,248				24,248
Property taxes		27,811	22,314		50,125
Unamortized sale and leaseback costs		16,454		56,099	72,553

Other	82,845	71,179	18,755	(51,114)	121,665
	217,038	497,293	41,069	(383,617)	371,783
	$ 5,821,127	$ 6,020,488	$ 5,282,211	$ (5,373,038)	$ 11,750,788
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$ 736	$ 646,402	$ 922,429	$ (18,640)	$ 1,550,927
Short-term borrowings					
Associated companies		9,237			9,237
Other	100,000				100,000
Accounts payable					
Associated companies	261,788	170,446	295,045	(261,201)	466,078
Other	51,722	193,641			245,363
Accrued taxes	44,213	61,055	22,777	(44,887)	83,158
Other	173,015	132,314	16,734	36,994	359,057
	631,474	1,213,095	1,256,985	(287,734)	2,813,820
CAPITALIZATION:					
Common stockholder s equity	3,514,571	2,346,515	2,119,488	(4,466,003)	3,514,571
Long-term debt and other long-term obligations	1,519,339	1,906,818	554,825	(1,269,330)	2,711,652
	5,033,910	4,253,333	2,674,313	(5,735,333)	6,226,223
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction				992,869	992,869
Accumulated deferred income taxes			342,840	(342,840)	
Accumulated deferred investment tax credits		36,359	22,037		58,396
Asset retirement obligations		25,714	895,734		921,448
Retirement benefits	33,144	170,891			204,035
Property taxes		27,811	22,314		50,125
Lease market valuation liability		262,200			262,200
Other	122,599	31,085	67,988		221,672
	155,743	554,060	1,350,913	650,029	2,710,745
	$ 5,821,127	$ 6,020,488	$ 5,282,211	$ (5,373,038)	$ 11,750,788

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FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Unaudited)

For the Six Months Ended June 30, 2010	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (223,072)	$ 163,325	$ 287,376	$ (9,174)	$ 218,455
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing					
Short-term borrowings, net		75,891			75,891
Redemptions and Repayments					
Long-term debt	(397)	(260,865)	(42,949)	9,174	(295,037)
Short-term borrowings, net					
Other	(457)	(128)	(101)		(686)
Net cash used for financing activities	(854)	(185,102)	(43,050)	9,174	(219,832)
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(3,716)	(333,063)	(229,408)		(566,187)
Proceeds from asset sales		115,657			115,657
Sales of investment securities held in trusts			956,813		956,813
Purchases of investment securities held in trusts			(978,785)		(978,785)
Loans from associated companies, net	332,067	240,836	58,270		631,173
Customer acquisition costs	(104,795)				(104,795)
Leasehold improvement payments to associated companies			(51,204)		(51,204)
Other	370	(1,654)	(12)		(1,296)
Net cash provided from (used for) investing activities	223,926	21,776	(244,326)		1,376
Net change in cash and cash equivalents		(1)			(1)
Cash and cash equivalents at beginning of period		3	9		12
Cash and cash equivalents at end of period	$	$ 2	$ 9	$	$ 11

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FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Unaudited)

For the Six Months Ended June 30, 2009	FES	FGCO	NGC	Eliminations	Consolidated
			(In thousands)		
NET CASH PROVIDED FROM OPERATING ACTIVITIES	$ 285,284	$ 314,041	$ 221,625	$ (8,734)	$ 812,216
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing					
Long-term debt		347,710	333,965		681,675
Short-term borrowings, net	98,880		128,716	(82,587)	145,009
Redemptions and Repayments					
Long-term debt	(1,696)	(260,372)	(369,519)	8,734	(622,853)
Short-term borrowings, net		(82,587)		82,587	
Net cash provided from financing activities	97,184	4,751	93,162	8,734	203,831
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(694)	(332,789)	(301,484)		(634,967)
Proceeds from asset sales		15,771			15,771
Sales of investment securities held in trusts			537,078		537,078
Purchases of investment securities held in trusts			(550,730)		(550,730)
Loans to associated companies, net	(261,839)	20,669			(241,170)
Other	65	(22,448)	349		(22,034)
Net cash used for investing activities	(262,468)	(318,797)	(314,787)		(896,052)
Net change in cash and cash equivalents	120,000	(5)			119,995
Cash and cash equivalents at beginning of period		39			39
Cash and cash equivalents at end of period	$ 120,000	$ 34	$	$	$ 120,034

13. INTANGIBLE ASSETS

FES has acquired certain customer contract rights, which were capitalized as intangible assets. These rights allow FES to supply electric generation needs to customers and the recorded value is being amortized ratably over the term of the related contracts. Net intangible assets of $118 million are included in other assets on FirstEnergy s Consolidated Balance Sheet as of June 30, 2010.

For the three and six months ended June 30, 2010, amortization expense was approximately $3 million and $5 million, respectively.

14. ASSET RETIREMENT OBLIGATIONS

FirstEnergy has recognized applicable legal obligations for AROs and their associated cost for nuclear power plant decommissioning, reclamation of a sludge disposal pond and closure of two 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 generating facilities (OE for their leasehold interest 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 and the Utilities use an expected cash flow approach to measure the fair value of their nuclear decommissioning AROs.

During the second quarter of 2010, studies were completed to reassess the estimated cost of decommissioning the Beaver Valley nuclear generating facility. The cost studies resulted in a revision to the estimated cash flows associated with the ARO liabilities of FES, OE and TE and reduced the liability for each subsidiary in the amounts of $88 million, $7 million, and $5 million, respectively, as of June 30, 2010.

The revision to the estimated cash flows had no significant impact on accretion expense during the second quarter of 2010 when compared to the second quarter of 2009.

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15. PROPOSED MERGER WITH ALLEGHENY ENERGY, INC.

As previously disclosed, on February 10, 2010, FirstEnergy entered into an Agreement and Plan of Merger, subsequently amended on June 4, 2010 (Merger Agreement) with Element Merger Sub, Inc., a Maryland corporation and its wholly-owned subsidiary (Merger Sub) and Allegheny Energy, Inc., a Maryland corporation (Allegheny Energy). Upon the terms and subject to the conditions set forth in the Merger Agreement, Merger Sub will merge with and into Allegheny Energy with Allegheny Energy continuing as the surviving corporation and a wholly-owned subsidiary of FirstEnergy. Pursuant to the Merger Agreement, upon the closing of the merger, each issued and outstanding share of Allegheny Energy common stock, including grants of restricted common stock, will automatically be converted into the right to receive 0.667 of a share of common stock of FirstEnergy and Allegheny Energy stockholders will own approximately 27% of the combined company. Based on the closing stock prices for both companies on February 10, 2010, Allegheny Energy shareholders would receive a value of $27.65 per share. On July 15, 2010 the most recent practicable date prior to the effectiveness of the Form S-4 registration statement, the exchange ratio represented approximately $25.06 in value for each share of Allegheny Energy common stock. FirstEnergy will also assume all outstanding Allegheny Energy debt.

Pursuant to the Merger Agreement, completion of the merger is conditioned upon, among other things, shareholder approval of both companies, the SEC s clearance of a registration statement registering the FirstEnergy common stock to be issued in connection with the merger, as well as expiration or termination of any applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 and approval by the FERC, the MDPSC, the PPUC, the VSCC and the PSCWV. The Merger Agreement also contains certain termination rights for both FirstEnergy and Allegheny Energy, and further provides for the payment of fees and expenses upon termination under specified circumstances.

FirstEnergy and Allegheny Energy currently anticipate completing the merger in the first half of 2011. Although FirstEnergy and Allegheny Energy believe that they will receive the required authorizations, approvals and consents to complete the merger, there can be no assurance as to the timing of these authorizations, approvals and consents or as to FirstEnergy s and Allegheny Energy s ultimate ability to obtain such authorizations, consents or approvals (or any additional authorizations, approvals or consents which may otherwise become necessary) or that such authorizations, approvals or consents will be obtained on terms and subject to conditions satisfactory to Allegheny Energy and FirstEnergy. Further information concerning the proposed merger is included in the Registration Statement filed by FirstEnergy with the SEC in connection with the merger.

In connection with the proposed merger, FirstEnergy recorded approximately $7 million ($5 million after tax) of merger transaction costs in the second quarter and approximately $21 million ($15 million after tax) of merger transaction costs in the first six months of 2010. These costs are expensed as incurred.

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

FIRSTENERGY CORP.

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

EXECUTIVE SUMMARY

Earnings available to FirstEnergy in the second quarter of 2010 were $265 million, or basic and diluted earnings of $0.87 per share of common stock, compared with $414 million, or basic and diluted earnings of $1.36 per share of common stock in the second quarter of 2009. Results in the second quarter of 2010 were adversely affected by the absence of a 2009 gain from the sale of a 9% participation interest in OVEC. Earnings available to FirstEnergy in the first six months of 2010 were $420 million or basic earnings of $1.38 ($1.37 diluted) per share of common stock, compared with $533 million, or basic and diluted earnings of $1.75 per share of common stock in the first six months of 2009.

Change in Basic Earnings Per Share From Prior Year	Three Months Ended June 30	Six Months Ended June 30
Basic Earnings Per Share 2009	$ 1.36	$ 1.75
Non-core asset sales/impairments	(0.52)	(0.54)
Trust securities impairments	(0.01)	0.04
Regulatory charges 2009		0.55
Regulatory charges 2010		(0.08)
Derivative mark-to-market adjustment 2010	0.07	(0.04)
Organizational restructuring 2009	0.01	0.06
Merger transaction costs 2010	(0.02)	(0.05)
Litigation settlements	0.04	0.04
Debt call premium 2009	0.01	0.01
Income tax resolution 2009		(0.04)
Income tax charge from healthcare legislation 2010		(0.04)
Revenues	0.23	0.16
Fuel and purchased power	(0.28)	(0.41)
Transmission expense	(0.08)	0.02
Amortization of regulatory assets, net	0.06	(0.11)
Investment income	0.02	0.03
Other expenses	(0.02)	0.03
Basic Earnings Per Share 2010	$ 0.87	$ 1.38

Pending Merger

As previously disclosed, on February 10, 2010, FirstEnergy entered into an Agreement and Plan of Merger, subsequently amended on June 4, 2010, (Merger Agreement) with Element Merger Sub. Inc., a Maryland corporation and its wholly-owned subsidiary (Merger Sub) and Allegheny Energy, Inc., a Maryland corporation (Allegheny Energy). Upon the terms and subject to the conditions set forth in the Merger Agreement, Merger Sub will merge with and into Allegheny Energy with Allegheny Energy continuing as the surviving corporation and a wholly-owned subsidiary of FirstEnergy. Pursuant to the Merger Agreement, upon the closing of the merger, each issued and outstanding share of Allegheny Energy common stock, including grants of restricted common stock, will automatically be converted into the right to receive 0.667 of a share of common stock of FirstEnergy and Allegheny Energy stockholders will own approximately 27% of the combined company. Based on the closing stock prices for both companies on February 10, 2010, Allegheny Energy shareholders would receive a value of $27.65 per share. On July 15, 2010, the most recent practicable date prior to the effectiveness of the Form S-4 registration statement, the exchange ratio represented approximately $25.06 in value for each share of Allegheny Energy common stock. FirstEnergy will also assume all outstanding Allegheny Energy debt.

Pursuant to the Merger Agreement, completion of the merger is conditioned upon, among other things, shareholder approval of both companies, the SEC s clearance of a registration statement registering the FirstEnergy common stock to be issued in connection with the merger, as well as expiration or termination of any applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 and approval by the FERC, the MDPSC, the PPUC, the VSCC and the PSCWV. The Merger Agreement also contains certain termination rights for both FirstEnergy and Allegheny Energy, and further provides for the payment of fees and expenses upon termination under specified circumstances.

FirstEnergy and Allegheny Energy currently anticipate completing the merger in the first half of 2011. Although FirstEnergy and Allegheny Energy believe that they will receive the required authorizations, approvals and consents to complete the merger, there can be no assurance as to the timing of these authorizations, approvals and consents or as to FirstEnergy s and Allegheny Energy s ultimate ability to obtain such authorizations, consents or approvals (or any additional authorizations, approvals or consents which may otherwise become necessary) or that such authorizations, approvals or consents will be obtained on terms and subject to conditions satisfactory to Allegheny Energy and FirstEnergy. Further information concerning the proposed merger is included in the Registration Statement filed by FirstEnergy with the SEC in connection with the merger.

In connection with the proposed merger, FirstEnergy recorded approximately $7 million ($5 million after tax) of merger transaction costs in the second quarter and approximately $21 million ($15 million after tax) of merger transaction costs in the first six months of 2010. These costs are expensed as incurred.

FERC

On May 11, 2010, FirstEnergy and Allegheny Energy filed an application with the FERC for approval of their proposed merger. Under the Federal Power Act, FERC has 180 days to rule on the merger application. FirstEnergy and Allegheny Energy submitted additional information regarding the merger application on June 21, 2010 in response to a request by FERC. Interventions and protests were filed with the FERC on July 12, 2010.

State Regulatory Merger Filings

On May 14 and May 18, 2010, FirstEnergy and Allegheny Energy filed applications with the PPUC and the PSCWV, respectively, for approval of their proposed merger. Pennsylvania and West Virginia laws impose no statutory timeframe for their commissions consideration of a merger application, but procedural schedules have been established, and final decisions are anticipated early in 2011. On May 27, 2010, FirstEnergy and Allegheny Energy filed an application for approval of the proposed merger with the MDPSC. The MDPSC is required to issue an order no later than 180 days after an application is filed, but under good cause MDPSC may give itself a 45-day extension, which it did when it issued its initial order in the matter. An order from the MDPSC is therefore expected by January 7, 2011. On June 14, 2010, FirstEnergy and Allegheny Energy completed their application with the VSCC. The VSCC is required to rule on the merger application in 60 days, subject to up to a 120-day extension. In its order issued June 25, 2010, the VSCC extended the period for its review by 30 days; therefore the companies expect a decision by September 13, 2010.

Hart-Scott-Rodino (HSR) Act Filings

On May 25, 2010, FirstEnergy and Allegheny Energy made HSR filings with the DOJ and Federal Trade Commission. On June 24, 2010, FirstEnergy and Allegheny Energy each received a request for additional information from the DOJ, which extends the HSR Act waiting period for an additional 30 days from the date that the requested information is supplied to the DOJ.

Form S-4 Registration Statement

On July 16, 2010, FirstEnergy s registration statement on Form S-4 containing a joint proxy statement/prospectus relating to the proposed merger (Registration Statement) was declared effective by the SEC. The joint proxy statement/prospectus contained in the Registration Statement was first mailed to FirstEnergy and Allegheny Energy shareholders on or about July 23, 2010. FirstEnergy and Allegheny Energy will each hold a special meeting of shareholders on September 14, 2010 in connection with the proposed merger.

Financial Matters

Financing Activities

On June 1, 2010, FGCO purchased $15 million fixed rate of PCRBs originally issued on its behalf. Subject to market conditions, FGCO plans to remarket the $15 million of PCRBs, as well as $235 million of PCRBs purchased in April, in the near future.

Penn redeemed $1 million of PCRBs due October 1, 2013 on June 1, 2010 and $6.5 million of 7.65% FMBs due in 2023 on July 30, 2010.

During the second quarter of 2010, FirstEnergy executed 13 interest rate swap contracts totaling $3.2 billion. These contacts were subsequently terminated to take advantage of favorable market conditions, and resulted in cash proceeds of $126.7 million. These proceeds will generally be amortized to earnings over the life of the underlying debt.

Operational Matters

Davis-Besse Refueling

On June 3, 2010, modifications of 24 of the 69 control rod drive mechanism (CRDM) nozzles on the reactor head were completed at the Davis-Besse Nuclear Power Station. These nozzles were identified during Davis-Besse s refueling outage and reactor head inspection that began February 28, 2010. The extended outage at Davis-Besse resulted in a $5 million impact on O&M this quarter, while approximately $40 million of the costs related to the modifications to the CRDM were capitalized. The plant was originally scheduled to have a new reactor head installed in 2014. This timeline was voluntarily accelerated, and FirstEnergy announced that a new reactor head will be installed in the fall of 2011. The new head was manufactured in France and is expected to arrive at the plant in the fall of 2010 to undergo a series of pre-service inspections. Davis-Besse returned to service on June 29, 2010.

Legacy Power Contracts

In July 2010, FES entered into financial transactions that offset the mark-to-market impact of legacy purchased power contracts totaling 500 MW entered into in 2008 for delivery in 2010 and 2011 and which were marked to market beginning in December 2009. These financial transactions eliminate the volatility associated with marking these contracts to market through the end of 2011.

Regulatory Matters General

DOE Smart Grid Grants

On June 3, 2010, FirstEnergy and the DOE signed grants totaling $57.4 million that were awarded as part of the American Recovery and Reinvestment Act to introduce smart grid technologies in targeted areas in Pennsylvania, Ohio, and New Jersey. The DOE grants represent 50% of the funding for the $114.9 million FirstEnergy investment in smart grid technologies; the PPUC and the NJBPU have already approved recovery for the remaining portion of smart grid costs. The PUCO issued an order on June 30, 2010, approving FirstEnergy s smart grid program, but FirstEnergy has delayed implementation of the Ohio portion of the program until there is more certainty regarding cost recovery for the portion of the costs not covered by the grant.

Regulatory Matters Ohio

Electric Security Plan Filing

The Ohio Companies filed a second Supplemental Stipulation with the PUCO on July 22, 2010, to supplement the ESP Stipulation filed on March 23, 2010, and the Supplemental Stipulation filed on May 13, 2010. An additional four signatories were included in the Supplemental Stipulations, joining the Ohio Companies and 17 original signatory parties that support the ESP. A final PUCO order is pending.

Regulatory Matters Pennsylvania

Met-Ed and Penelec TSC

On May 20, 2010, the PPUC approved the revised TSC for Met-Ed and Penelec. The revised TSC rates were slightly increased for Met-Ed and slightly decreased for Penelec, and are effective for the period of June 1, 2010 to December 31, 2010. The PPUC s Order of March 3, 2010, which denies the recovery of marginal transmission losses through the TSC for the period of June 1, 2007 through March 31, 2008, remains subject to an appeal that is currently pending in the Commonwealth Court of Pennsylvania.

Met-Ed and Penelec Default Service Plan

On May 27, 2010, the third of four auctions held to procure the default service requirements for Met-Ed and Penelec customers who choose not to shop with an alternative supplier. For the five-month period of January 1, 2011 to May 31, 2011, the tranche-weighted average prices ($/MWh) for Met-Ed s residential and commercial classes were $72.81 and $72.29, respectively; Penelec s tranche-weighted average prices were $62.04 and $63.35 for its residential and commercial classes, respectively. There will be another auction in October 2010 to procure the remaining supply for this period. The May 2010 auction was also the first of four auctions to procure commercial default service requirements for the 12-month period of June 1, 2011, to May 31, 2012 and residential requirements for the 24-month period of June 1, 2011, to May 31, 2013. For Met-Ed and Penelec commercial customers the tranche-weighted average price ($/MWh) was $66.32 and $57.60, respectively. The remaining three auctions for these products will be conducted in October 2010, January 2011 and March 2011.

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RPM Base Residual Auction

On May 14, 2010, PJM released the results of the 2013/2014 RPM Base Residual Auction. The auction cleared 152,743 MW of unforced capacity in the RTO Zone, which includes the ATSI zone, at the Resource Clearing Price of $27.73/MW-day. The Clearing Price in MAAC, which includes Met-Ed and Penelec zones and EMAAC which includes the Jersey Central zone, were $226.15/MW-day and $245.00/MW-day, respectively.

FIRSTENERGY S BUSINESS

FirstEnergy is a diversified energy company headquartered in Akron, Ohio, that operates primarily through two core business segments (see Results of Operations).

Energy Delivery Services transmits and distributes electricity through our eight utility operating companies, serving 4.5 million customers within 36,100 square miles of Ohio, Pennsylvania and New Jersey and purchases power for its POLR and default service requirements in Ohio, Pennsylvania and New Jersey. Its revenues are primarily derived from the delivery of electricity within our service areas, cost recovery of regulatory assets and the sale of electric generation service to retail customers who have not selected an alternative supplier (default service) in its Ohio, Pennsylvania and New Jersey franchise areas. Its results reflect the commodity costs of securing electric generation from FES and from non-affiliated power suppliers, the net PJM and MISO transmission expenses related to the delivery of the respective generation loads, and the deferral and amortization of certain fuel costs.

Competitive Energy Services supplies electric power to end-use customers through retail and wholesale arrangements, including associated company power sales to meet all or a portion of the POLR and default service requirements of our Ohio and Pennsylvania utility subsidiaries and competitive retail sales to customers primarily in Ohio, Pennsylvania, Maryland and Michigan. This business segment controls approximately 14,000 MW 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 revenues less the related costs of electricity generation, including purchased power and net transmission (including congestion) and ancillary costs charged by PJM and MISO to deliver energy to the segment s customers.

RESULTS OF OPERATIONS

The financial results discussed below include revenues and expenses from transactions among FirstEnergy s business segments. A reconciliation of segment financial results is provided in Note 11 to the consolidated financial statements. Earnings available to FirstEnergy by major business segment were as follows:

	Three Months Ended June 30			Six Months Ended June 30		
	2010	**2009**	**Increase (Decrease)**	**2010**	**2009**	**Increase (Decrease)**
	(In millions, except per share data)					
Earnings By Business Segment:						
Energy delivery services	$ 143	$ 154	$ (11)	$ 257	$ 136	$ 121
Competitive energy services	125	276	(151)	201	431	(230)
Other and reconciling adjustments*	(3)	(16)	13	(38)	(34)	(4)
Total	$ 265	$ 414	$ (149)	$ 420	$ 533	$ (113)
Basic Earnings Per Share	$ 0.87	$ 1.36	$ (0.49)	$ 1.38	$ 1.75	$ (0.37)
Diluted Earnings Per Share	$ 0.87	$ 1.36	$ (0.49)	$ 1.37	$ 1.75	$ (0.38)

*

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

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Summary of Results of Operations Second Quarter 2010 Compared with Second Quarter 2009

Financial results for FirstEnergy s major business segments in the second quarter of 2010 and 2009 were as follows:

Second Quarter 2010 Financial Results	Energy Delivery Services	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
		(In millions)		
Revenues:				
External				
Electric	$ 2,243	$ 728	$	$ 2,971
Other	130	50	(23)	157
Internal	19	539	(558)	
Total Revenues	2,392	1,317	(581)	3,128
Expenses:				
Fuel		351	(1)	350
Purchased power	1,291	319	(558)	1,052
Other operating expenses	352	337	(16)	673
Provision for depreciation	115	66	9	190
Amortization of regulatory assets	161			161
Deferral of new regulatory assets				
General taxes	145	25	6	176
Total Expenses	2,064	1,098	(560)	2,602
Operating Income	328	219	(21)	526
Other Income (Expense):				
Investment income	27	13	(9)	31
Interest expense	(124)	(55)	(28)	(207)
Capitalized interest	1	24	15	40
Total Other Expense	(96)	(18)	(22)	(136)
Income Before Income Taxes	232	201	(43)	390
Income taxes	89	76	(31)	134
Net Income (Loss)	143	125	(12)	256
Noncontrolling interest loss			(9)	(9)
Earnings available to FirstEnergy Corp.	$ 143	$ 125	$ (3)	$ 265

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Second Quarter 2009 Financial Results	Energy Delivery Services	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
		(In millions)		
Revenues:				
External				
Electric	$ 2,657	$ 205	$	$ 2,862
Other	135	299	(25)	409
Internal		839	(839)	
Total Revenues	2,792	1,343	(864)	3,271
Expenses:				
Fuel		276		276
Purchased power	1,677	186	(839)	1,024
Other operating expenses	328	315	(31)	612
Provision for depreciation	110	68	7	185
Amortization of regulatory assets	233			233
Deferral of new regulatory assets	(45)			(45)
General taxes	154	25	5	184
Total Expenses	2,457	870	(858)	2,469
Operating Income	335	473	(6)	802
Other Income (Expense):				
Investment income	35	6	(14)	27
Interest expense	(114)	(32)	(60)	(206)
Capitalized interest	1	14	18	33
Total Other Expense	(78)	(12)	(56)	(146)
Income Before Income Taxes	257	461	(62)	656
Income taxes	103	185	(40)	248
Net Income (Loss)	154	276	(22)	408
Noncontrolling interest loss			(6)	(6)
Earnings available to FirstEnergy Corp.	$ 154	$ 276	$ (16)	$ 414

Changes Between Second Quarter 2010 and Second Quarter 2009 Financial Results Increase (Decrease)

Revenues:				
External				
Electric	$ (414)	$ 523	$	$ 109
Other	(5)	(249)	2	(252)
Internal	19	(300)	281	
Total Revenues	(400)	(26)	283	(143)
Expenses:				
Fuel		75	(1)	74
Purchased power	(386)	133	281	28
Other operating expenses	24	22	15	61
Provision for depreciation	5	(2)	2	5
Amortization of regulatory assets	(72)			(72)
Deferral of new regulatory assets	45			45
General taxes	(9)		1	(8)
Total Expenses	(393)	228	298	133
Operating Income	(7)	(254)	(15)	(276)
Other Income (Expense):				
Investment income	(8)	7	5	4
Interest expense	(10)	(23)	32	(1)
Capitalized interest		10	(3)	7
Total Other Expense	(18)	(6)	34	10
Income Before Income Taxes	(25)	(260)	19	(266)
Income taxes	(14)	(109)	9	(114)
Net Income (Loss)	(11)	(151)	10	(152)
Noncontrolling interest loss			(3)	(3)
Earnings available to FirstEnergy Corp.	$ (11)	$ (151)	$ 13	$ (149)

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Energy Delivery Services — Second Quarter 2010 Compared with Second Quarter 2009

Net income decreased by $11 million in the second quarter of 2010, compared to the second quarter of 2009, primarily due to lower generation-related revenues and the absence of deferrals of new regulatory assets, partially offset by lower amortization of regulatory assets and purchased power costs.

Revenues

The decrease in total revenues resulted from the following sources:

Revenues by Type of Service	Three Months Ended June 30 2010	2009	Increase (Decrease)
		(In millions)	
Distribution services	$ 851	$ 813	$ 38
Generation sales:			
Retail	1,097	1,514	(417)
Wholesale	180	162	18
Total generation sales	1,277	1,676	(399)
Transmission	200	259	(59)
Other	64	44	20
Total Revenues	$ 2,392	$ 2,792	$ (400)

The increase in distribution deliveries by customer class is summarized in the following table:

Electric Distribution KWH Deliveries	
Residential	7%
Commercial	5%
Industrial	13%
Total Distribution KWH Deliveries	8%

Higher deliveries to residential and commercial customers reflected increased weather-related usage in the second quarter of 2010, as cooling degree days increased by 94% from the same period in 2009. The increase in distribution deliveries to industrial customers was primarily due to recovering economic conditions in FirstEnergy s service territory compared to the second quarter of 2009. In the industrial sector, KWH deliveries increased to major automotive customers (39%) and steel customers (60%). Distribution service revenues increased primarily due to the recovery of the PA Energy Efficiency and Conservation charges as approved by the PPUC in March 2010 and the accelerated recovery of deferred distribution costs in Ohio, partially offset by a reduction in the transition rate for CEI effective June 1, 2009.

The following table summarizes the price and volume factors contributing to the $399 million decrease in generation revenues in the second quarter of 2010 compared to the second quarter of 2009:

Source of Change in Generation Revenues	Increase (Decrease)
	(In millions)

Retail:		
Effect of 29.4% decrease in sales volumes	$	(444)
Change in prices		27
		(417)
Wholesale:		
Effect of 10.1% decrease in sales volumes		(16)
Change in prices		34
		18
Decrease in Generation Revenues	$	(399)

The decrease in retail generation sales volumes was primarily due to an increase in customer shopping in the Ohio Companies service territories in the second quarter of 2010, which is expected to continue to impact retail generation sales, partially offset by higher generation revenues related to the recovery of transmission costs now provided for in the generation rate established under the CBP. Total generation KWH provided by alternative suppliers as a percentage of total KWH deliveries for the Ohio Companies increased to 61% in the second quarter of 2010, as there was no shopping in the second quarter 2009.

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The increase in wholesale generation revenues reflected higher prices for Met-Ed s and Penelec s sales of NUG power to the PJM market.

Transmission revenues decreased $59 million primarily due to the termination of the Ohio Companies transmission tariff effective June 1, 2009; recovery of transmission costs is now through the generation rate established under the CBP.

Expenses

Total expenses decreased by $393 million due to the following:

Purchased power costs were $386 million lower in the second quarter of 2010 due to lower volume requirements, partially offset by an increase in unit costs from non-affiliates. The decrease in purchased power volumes from non-affiliates resulted principally from the termination of a third-party supply contract for Met-Ed and Penelec in January 2010 and from the above described increase in customer shopping in the Ohio Companies service territories. The decrease in volumes from FES principally resulted from the increase in customer shopping in the Ohio Companies service territories, as described above.

The increase in unit costs from non-affiliates in the second quarter of 2010 resulted from higher capacity prices in the PJM market for Met-Ed and Penelec compared to the second quarter of 2009. The decrease in unit costs from FES was principally due to the lower weighted average unit price per KWH for the Ohio Companies established under the CBP auction effective June 1, 2009.

Source of Change in Purchased Power	**Increase (Decrease)** *(In millions)*
Purchases from non-affiliates:	
Change due to increased unit costs	$ 156
Change due to decreased volumes	(280)
	(124)
Purchases from FES:	
Change due to decreased unit costs	(67)
Change due to decreased volumes	(191)
	(258)
Increase in NUG costs deferred	(4)
Net Decrease in Purchased Power Costs	$ (386)

Administrative and general costs, including labor and employee benefit expenses, increased $9 million primarily due to a higher level of incentive compensation earned this year, partially offset by lower payroll expenses due to staffing reductions implemented in 2009.

Energy Efficiency program costs increased $14 million in the second quarter of 2010 compared to the second quarter of 2009.

Forestry contractor costs decreased by $3 million in the second quarter of 2010 compared to the second quarter of 2009, as more resources were dedicated to capital projects in 2010.

A favorable JCP&L labor settlement reduced expenses by $7 million in the second quarter of 2010.

Transmission costs, net of regulatory asset amortization expense, decreased by $61 million primarily due to the transfer of transmission cost responsibility to generation providers under the CBP.

The deferral of new regulatory assets decreased $45 million in the second quarter of 2010 principally due to reduced CEI purchased power cost deferrals in the second quarter of 2009.

Depreciation expense increased $5 million due to property additions since the second quarter of 2009.

General taxes decreased $9 million primarily due to a favorable Ohio property tax settlement in 2010.

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Other Expense

Other expense increased $18 million in the second quarter of 2010 compared to the second quarter of 2009 primarily due to higher interest expense associated with debt issuances by the Utilities since the second quarter of 2009.

Competitive Energy Services   Second Quarter 2010 Compared with Second Quarter 2009

Net income decreased by $151 million in the second quarter of 2010, compared to the second quarter of 2009, primarily due to the absence of a $252 million gain ($158 million after tax) in 2009 from the sale of a 9% participation interest in OVEC.

Revenues

Total revenues, excluding the OVEC sale, increased $226 million in the second quarter of 2010 primarily due to an increase in direct and government aggregation sales volumes, partially offset by decreases in POLR sales to the Ohio Companies and wholesale sales.

The decrease in total revenues resulted from the following sources:

Revenues by Type of Service	**Three Months Ended June 30 2010**	**2009**	**Increase (Decrease)**
		(In millions)	
Direct and Government Aggregation	$ 586	$ 83	$ 503
POLR	586	839	(253)
Wholesale	95	122	(27)
Transmission	19	16	3
Sale of OVEC participation interest		252	(252)
Other	31	31	
Total Revenues	$ 1,317	$ 1,343	$ (26)

The increase in direct and government aggregation revenues of $503 million resulted from increased revenue in both the MISO and PJM markets. The increase in revenue primarily resulted from the acquisition of new commercial and industrial customers as well as new government aggregation contracts with communities in Ohio that provide generation to 1.1 million residential and small commercial customers at the end of June 2010 compared to 21,000 at the end of June 2009.

The decrease in POLR revenues of $253 million was due to lower sales volumes to the Ohio Companies and lower unit prices, partially offset by increased sales volumes and higher unit prices to the Pennsylvania Companies. The lower sales volumes and unit prices to the Ohio Companies in the second quarter 2010 reflected the results of the May 2009 power procurement process. The increased revenues to the Pennsylvania Companies resulted from FES supplying Met-Ed and Penelec with volumes previously supplied through a third-party contract and at prices that were slightly higher than in the second quarter of 2009.

Wholesale revenues decreased $27 million due to reduced volumes, reflecting increased retail sales in Ohio and lower prices.

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

Source of Change in Direct and Government Aggregation	**Increase (Decrease)**
	(In millions)
Direct Sales:	
Effect of increase in sales volumes	$ 345
Change in prices	(16)

		329
Government Aggregation:		
Effect of increase in sales volumes		174
Change in prices		
		174
Net Increase in Direct and Gov t Aggregation Revenues	$	503

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Source of Change in Wholesale Revenues	Decrease (In millions)
POLR:	
Effect of 20.4% decrease in sales volumes	$ (171)
Change in prices	(82)
	(253)
Wholesale:	
Effect of 21.9% decrease in sales volumes	(15)
Change in prices	(12)
	(27)
Decrease in Wholesale Revenues	$ (280)

Transmission revenues increased $3 million due primarily to higher MISO congestion revenue.

Expenses

Total expenses increased $228 million in the second quarter of 2010 due to the following:

Fuel costs increased $75 million due to increased generation volumes primarily at the fossil units ($73 million) and higher unit prices ($2 million). The increase in unit prices was due primarily to higher nuclear fuel unit prices following the refueling outages that occurred in 2009.

Purchased power costs increased $133 million due primarily to higher volumes purchased ($162 million) and higher unit costs ($6 million), partially offset by power contract mark-to-market adjustments ($35 million). In July 2010, FES entered into financial transactions that offset the mark-to-market impact of legacy purchased power contracts totaling 500 MW entered into in 2008 for delivery in 2010 and 2011 and which were marked-to-market beginning in December 2009. These financial transactions eliminate the volatility associated with marking these contracts to market through the end of 2011.

Fossil operating costs decreased $3 million due primarily to lower professional and contractor costs, partially offset by reduced gains on the sale of emission allowances.

Nuclear operating costs decreased $17 million due primarily to lower labor and professional and contractor costs due to one less refueling outage in 2010 as compared to the same period of 2009.

Transmission expenses increased $26 million due primarily to increases in MISO of $63 million from higher network and ancillary costs, partially offset by lower PJM transmission expenses of $37 million due to lower congestion and loss costs.

Other expenses increased $14 million primarily due to increases in uncollectible customer accounts and agent fees associated with the growth in direct and government aggregation sales.

Other Expense

Total other expense in the second quarter of 2010 was $6 million higher than the second quarter of 2009, primarily due to a $13 million increase in interest expense from new long-term debt issued combined with the restructuring of existing long-term debt, partially offset by a $7 million increase in investment income resulting from more favorable performance of the nuclear decommissioning trust investments ($6 million).

Other Second Quarter of 2010 Compared with Second Quarter of 2009

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 $13 million increase in earnings available to FirstEnergy in the first quarter of 2010 compared to the same period in 2009. The increase resulted primarily from reduced interest expense on holding company debt resulting from the September 2009 tender offer ($20M), partially offset by increased operating expenses.

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Summary of Results of Operations First Six Months of 2010 Compared with the First Six Months of 2009

Financial results for FirstEnergy s major business segments in the first six months of 2010 and 2009 were as follows:

First Six Months 2010 Financial Results	Energy Delivery Services	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)	
Revenues:				
External				
Electric	$ 4,641	$ 1,397	$	$ 6,038
Other	275	97	(50)	322
Internal*	19	1,213	(1,165)	67
Total Revenues	4,935	2,707	(1,215)	6,427
Expenses:				
Fuel		688	(4)	684
Purchased power	2,686	769	(1,165)	2,290
Other operating expenses	732	684	(42)	1,374
Provision for depreciation	228	132	23	383
Amortization of regulatory assets	373			373
Deferral of new regulatory assets				
General taxes	307	60	14	381
Total Expenses	4,326	2,333	(1,174)	5,485
Operating Income	609	374	(41)	942
Other Income (Expense):				
Investment income	52	14	(19)	47
Interest expense	(248)	(108)	(64)	(420)
Capitalized interest	2	44	35	81
Total Other Expense	(194)	(50)	(48)	(292)
Income Before Income Taxes	415	324	(89)	650
Income taxes	158	123	(36)	245
Net Income (Loss)	257	201	(53)	405
Noncontrolling interest loss			(15)	(15)
Earnings available to FirstEnergy Corp.	$ 257	$ 201	$ (38)	$ 420

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First Six Months 2009 Financial Results	Energy Delivery Services	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
		(In millions)		
Revenues:				
External				
Electric	$ 5,518	$ 485	$	$ 6,003
Other	295	354	(47)	602
Internal		1,732	(1,732)	
Total Revenues	5,813	2,571	(1,779)	6,605
Expenses:				
Fuel		588		588
Purchased power	3,553	346	(1,732)	2,167
Other operating expenses	827	670	(58)	1,439
Provision for depreciation	219	132	11	362
Amortization of regulatory assets	642			642
Deferral of new regulatory assets	(136)			(136)
General taxes	324	57	14	395
Total Expenses	5,429	1,793	(1,765)	5,457
Operating Income	384	778	(14)	1,148
Other Income (Expense):				
Investment income	65	(23)	(26)	16
Interest expense	(224)	(60)	(116)	(400)
Capitalized interest	2	24	35	61
Total Other Expense	(157)	(59)	(107)	(323)
Income Before Income Taxes	227	719	(121)	825
Income taxes	91	288	(77)	302
Net Income (Loss)	136	431	(44)	523
Noncontrolling interest loss			(10)	(10)
Earnings available to FirstEnergy Corp.	$ 136	$ 431	$ (34)	$ 533

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Changes Between First Six Months 2010 and First Six Months 2009 Financial Results Increase (Decrease)

Revenues:								
External								
Electric	$	(877)	$	912	$		$	35
Other		(20)		(257)		(3)		(280)
Internal*		19		(519)		567		67
Total Revenues		(878)		136		564		(178)
Expenses:								
Fuel				100		(4)		96
Purchased power		(867)		423		567		123
Other operating expenses		(95)		14		16		(65)
Provision for depreciation		9				12		21
Amortization of regulatory assets		(269)						(269)
Deferral of new regulatory assets		136						136
General taxes		(17)		3				(14)
Total Expenses		(1,103)		540		591		28
Operating Income		225		(404)		(27)		(206)
Other Income (Expense):								
Investment income		(13)		37		7		31
Interest expense		(24)		(48)		52		(20)
Capitalized interest				20				20
Total Other Expense		(37)		9		59		31
Income Before Income Taxes		188		(395)		32		(175)
Income taxes		67		(165)		41		(57)
Net Income (Loss)		121		(230)		(9)		(118)
Noncontrolling interest loss						(5)		(5)
Earnings available to FirstEnergy Corp.	$	121	$	(230)	$	(4)	$	(113)

* Under the accounting standard for the effects of

certain types of regulation, internal revenues are not fully offset for sale of RECs by FES to the Ohio Companies that are retained in inventory.

Energy Delivery Services First Six Months of 2010 Compared to First Six Months of 2009

Net income increased by $121 million in the first six months of 2010, compared to the first six months of 2009, primarily due to the absence of CEI s $216 million regulatory asset impairment in 2009, lower purchased power costs and lower other operating expenses, partially offset by lower generation related revenues and decreased deferrals of new regulatory assets.

Revenues

The decrease in total revenues resulted from the following sources:

Revenues by Type of Service	Six Months Ended June 30 2010	2009	Increase (Decrease)
		(In millions)	
Distribution services	$ 1,733	$ 1,662	$ 71
Generation sales:			
Retail	2,274	3,128	(854)
Wholesale	397	349	48
Total generation sales	2,671	3,477	(806)
Transmission	415	577	(162)
Other	116	97	19
Total Revenues	$ 4,935	$ 5,813	$ (878)

The increase in distribution deliveries by customer class is summarized in the following table:

Electric Distribution KWH Deliveries	
Residential	1%
Commercial	2%
Industrial	10%
Total Distribution KWH Deliveries	4%

Higher deliveries to residential and commercial customers reflected increased weather-related usage in the first six months of 2010. Cooling degree days increased by 94%, partially offset by a 10% decrease in heating degree days from the same period in 2009. The increase in distribution deliveries to industrial customers was primarily due to recovering economic conditions in FirstEnergy s service territory compared to the first six months of 2009. In the industrial sector, KWH deliveries increased to major automotive customers (26%) and steel customers (44%).
Distribution service revenues increased primarily due to the recovery of the PA Energy Efficiency and Conservation charges as approved by the PPUC in March 2010 and the accelerated recovery of deferred distribution costs in Ohio, partially offset by a reduction in the transition rate for CEI effective June 1, 2009.
The following table summarizes the price and volume factors contributing to the $806 million decrease in generation revenues in the first six months of 2010 compared to the same period of 2009:

Source of Change in Generation Revenues	Increase (Decrease) *(In millions)*
Retail:	
Effect of 30% decrease in sales volumes	$ (939)
Change in prices	85
	(854)
Wholesale:	
Effect of 12.2% decrease in sales volumes	(42)
Change in prices	90
	48
Net Decrease in Generation Revenues	$ (806)

The decrease in retail generation sales volumes was primarily due to an increase in customer shopping in the Ohio Companies service territories in the first six months of 2010, which is expected to continue to impact retail generation sales, partially offset by higher generation revenues related to the recovery of transmission costs now provided for in the generation rate established under the CBP. Total generation KWH provided by alternative suppliers as a percentage of total KWH deliveries for the Ohio Companies increased to 57% in the first six months of 2010, as there was no shopping in the same period of 2009.
The increase in wholesale generation revenues reflected higher prices for Met-Ed s and Penelec s NUG sales to the PJM market.
Transmission revenues decreased $162 million primarily due to the termination of the Ohio Companies transmission tariff effective June 1, 2009; recovery of transmission costs is now through the generation rate established under the CBP.

Expenses

Total expenses decreased by $1,103 million due to the following:

- Purchased power costs were $867 million lower in the first six months of 2010 due to lower volume requirements, partially offset by an increase in unit costs for purchased power from non-affiliates. The decrease in volumes from non-affiliates resulted principally from the termination of a third-party supply contract for Met-Ed and Penelec in January 2010 and from the above described increase in customer shopping in the Ohio Companies service territories. The decrease in volumes from FES principally resulted from the increase in customer shopping in the Ohio Companies service territories, as described above.

  The increase in unit costs from non-affiliates in the first six months of 2010 resulted from higher capacity prices in the PJM market for Met-Ed and Penelec compared to the first six months of 2009. The decrease in unit costs from FES was principally due to the lower weighted average unit price per KWH for the Ohio Companies established under the CBP auction effective June 1, 2009.

Source of Change in Purchased Power	Increase (Decrease) (In millions)
Purchases from non-affiliates:	
Change due to increased unit costs	$ 346
Change due to decreased volumes	(703)
	(357)
Purchases from FES:	
Change due to decreased unit costs	(160)
Change due to decreased volumes	(343)
	(503)
Increase in NUG costs deferred	(7)
Net Decrease in Purchased Power Costs	$ (867)

MISO/PJM transmission expenses decreased $43 million primarily due to the recovery of transmission costs now provided for in the generation rate established under the CBP, partially offset by higher PJM congestion charges.

Administrative and general costs, including labor and employee benefits expenses, decreased by $22 million in the first six month of 2010 compared to 2009 due to lower payroll expenses resulting from staffing reductions implemented in 2009.

Other operating expenses decreased $28 million due to higher economic development commitments recognized in the first quarter of 2009 relating to the amended ESP and a favorable labor settlement of $7 million for JCP&L recognized in the second quarter of 2010.

Amortization of regulatory assets decreased $269 million due primarily to the absence of the $216 million impairment of CEI s regulatory assets in the second quarter of 2009, reduced transmission cost amortization and reduced CTC amortization for Met-Ed and Penelec, partially offset by a $35 million regulatory asset impairment associated with the filing of the Ohio Companies ESP on March 23, 2010.

The deferral of new regulatory assets decreased $136 million in the first six months of 2010 principally due to reduced CEI purchased power cost deferrals in the second quarter of 2009.

Depreciation expense increased $9 million due to property additions since the second quarter of 2009.

General taxes decreased $17 million due to favorable Ohio and Pennsylvania tax settlements in 2010.

Other Expense

Other expense increased $37 million in the first six months of 2010 compared to the first six months of 2009 primarily due to higher interest expense associated with debt issuances by the Utilities since the second quarter of 2009.

Competitive Energy Services First Six Months of 2010 Compared to First Six Months of 2009

Net income decreased by $230 million in the first six months of 2010, compared to the first six months of 2009, primarily due to the absence of a $252 million ($158 million after tax) gain in 2009 from the sale of a 9% participation in OVEC and a decrease in sales margins.

Revenues

Total revenues, excluding the OVEC sale, increased $388 million in the first six months of 2010 compared to the same period in 2009 primarily due to an increase in direct and government aggregation sales volumes and sales of RECs, partially offset by decreases in POLR sales to the Ohio Companies and wholesale sales.

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The increase in reported segment revenues resulted from the following sources:

Revenues by Type of Service	Six Months Ended June 30 2010	2009	Increase (Decrease)
	(In millions)		
Direct and Government Aggregation	$ 1,097	$ 174	$ 923
POLR	1,260	1,732	(472)
Wholesale	186	311	(125)
Transmission	36	41	(5)
RECs	67		67
Sale of OVEC participation interest		252	(252)
Other	61	61	
Total Revenues	$ 2,707	$ 2,571	$ 136

The increase in direct and government aggregation revenues of $923 million resulted from increased revenue in both the MISO and PJM markets. The increase in revenue primarily resulted from the acquisition of new commercial and industrial customers, as well as new government aggregation contracts with communities in Ohio that provide generation to 1.1 million residential and small commercial customers at the end of June 2010 compared to 21,000 at the end of June 2009, partially offset by lower unit prices. During January 2010, FES began supplying power to approximately 425,000 NOPEC customers.

The decrease in POLR revenues of $472 million was due to lower sales volumes to the Ohio Companies and lower unit prices, partially offset by increased sales volumes and higher unit prices to the Pennsylvania Companies. The lower sales volumes and unit prices to the Ohio Companies in 2010 reflected the results of the May 2009 power procurement process. The increased revenues to the Pennsylvania Companies resulted from FES supplying Met-Ed and Penelec with volumes previously supplied through a third-party contract and at prices that were slightly higher than in 2009.

Wholesale revenues decreased $125 million due to reduced volumes reflecting market declines and lower prices.

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

Source of Change in Direct and Government Aggregation	Increase (Decrease)
	(In millions)
Direct Sales:	
Effect of increase in sales volumes	$ 633
Change in prices	(47)
	586
Government Aggregation:	
Effect of increase in sales volumes	337
Change in prices	
	337
Net Increase in Direct and Gov t Aggregation Revenues	$ 923

Source of Change in Wholesale Revenues	**Decrease** *(In millions)*
POLR:	
Effect of 15.1% decrease in sales volumes	$ (262)
Change in prices	(210)
	(472)
Wholesale:	
Effect of 56.7% decrease in sales volumes	(123)
Change in prices	(2)
	(125)
Decrease in Wholesale Revenues	$ (597)

Transmission revenues decreased $5 million due primarily to lower PJM congestion revenue.

Expenses

Total expenses increased $540 million in the first six months of 2010 due to the following factors:

- Fuel costs increased $100 million due to increased generation volumes ($44 million) and higher unit prices ($56 million). The increase in unit prices was due primarily to higher nuclear fuel unit prices following the refueling outages that occurred in 2009 and increased coal transportation costs.
- Purchased power costs increased $423 million due primarily to higher volumes purchased ($484 million), and power contract mark-to-market adjustments ($17 million), partially offset by lower unit costs ($78 million). In July 2010, FES entered into financial transactions that offset the mark-to-market impact of legacy purchased power contracts totaling 500 MW entered into in 2008 for delivery in 2010 and 2011 and which were marked-to-market beginning in December 2009. These financial transactions eliminate the volatility associated with marking these contracts to market through the end of 2011.
- Fossil operating costs decreased $2 million due primarily to lower labor costs which were partially offset by higher professional and contractor costs and reduced gains on the sale of emission allowances.
- Nuclear operating costs decreased $37 million due primarily to lower labor and professional and contractor costs. The six months ended June 2010 had one less refueling outage and fewer extended outages than the same period of 2009.
- Transmission expenses increased $33 million due primarily to increased costs in MISO of $106 million from higher network and ancillary costs, partially offset by lower PJM transmission expenses of $73 million due to lower congestion and loss costs.
- Other expenses increased $20 million primarily due to increases in uncollectible customer accounts and agent fees associated with the growth in direct and government aggregation sales.

- General taxes increased $3 million due to sales taxes on higher revenues.

Other Expense

Total other expense in the six months ending June 2010 was $9 million lower than the same period in 2009, primarily due to a $37 million increase in investment income resulting from more favorable performance of the nuclear decommissioning trust investments, partially offset by a $28 million increase in interest expense. Interest expense increased because of new issuances of long-term debt combined with the restructuring of existing long-term debt.

Other First Six Months of 2010 Compared to First Six Months of 2009

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 $4 million decrease in earnings available to FirstEnergy in the first six months of 2010 compared to the same period in 2009. The decrease resulted primarily from increased other operating expenses and depreciation ($28 million) and increased income tax expense ($41 million), partially offset by reduced interest expense on holding company debt ($52 million) which was primarily the result of a September 2009 tender offer.

CAPITAL RESOURCES AND LIQUIDITY

FirstEnergy expects its existing sources of liquidity to remain sufficient to meet its anticipated obligations and those of its subsidiaries. FirstEnergy s business is capital intensive, requiring significant resources to fund operating expenses, construction expenditures, scheduled debt maturities and interest and dividend payments. During 2010 and in subsequent years, FirstEnergy expects to satisfy these requirements with a combination of cash from operations and funds from the capital markets as market conditions warrant. FirstEnergy also expects that borrowing capacity under credit facilities will continue to be available to manage working capital requirements during those periods.

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As of June 30, 2010, FirstEnergy s net deficit in working capital (current assets less current liabilities) was principally due to short-term borrowings ($1.5 billion) and the classification of certain variable interest rate PCRBs as currently payable long-term debt. Currently payable long-term debt as of June 30, 2010, included the following (in millions):

Currently Payable Long-term Debt	
PCRBs supported by bank LOCs [1]	$ 1,318
FGCO and NGC unsecured PCRBs [1]	75
Penelec FMBs [2]	24
NGC collateralized lease obligation bonds	50
Sinking fund requirements	41
Other notes [2]	63
	$ 1,571

(1) Interest rate mode permits individual debt holders to put the respective debt back to the issuer prior to maturity.

(2) Mature in November 2010.

Short-Term Borrowings

FirstEnergy had approximately $1.5 billion of short-term borrowings as of June 30, 2010 and $1.2 billion as of December 31, 2009. FirstEnergy s available liquidity as of July 31, 2010, is summarized in the following table:

Company	**Type**	**Maturity**	**Commitment**	**Available Liquidity**
			(In millions)	
FirstEnergy[1]	Revolving	Aug. 2012	$ 2,750	$ 1,407
FirstEnergy Solutions	Bank line	Mar. 2011	100	
Ohio and Pennsylvania Companies	Receivables financing	Various[2]	395	267
		Subtotal	$ 3,245	$ 1,674
		Cash		127
		Total	$ 3,245	$ 1,801

(1) FirstEnergy Corp. and subsidiary borrowers.

(2) Ohio $250 million matures March 30, 2011; Pennsylvania $145 million matures December 17, 2010

Revolving Credit Facility

FirstEnergy has the capability to request an increase in the total commitments available under the $2.75 billion revolving credit facility (included in the borrowing capability table above) up to a maximum of $3.25 billion, subject to the discretion of each lender to provide additional commitments. A total of 25 banks participate in the facility, with no one bank having more than 7.3% of the total commitment. Commitments under the facility are available until August 24, 2012, unless the lenders agree, at the request of the borrowers, to an unlimited number of additional one-year extensions. Generally, borrowings under the facility must be repaid within 364 days. Available amounts for each borrower are subject to a specified sub-limit, as well as applicable regulatory and other limitations.

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The following table summarizes the borrowing sub-limits for each borrower under the facility, 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 June 30, 2010:

Borrower	Revolving Credit Facility Sub-Limit	Regulatory and Other Short-Term Debt Limitations
	(In millions)	
FirstEnergy	$ 2,750	$ (1)
FES	1,000	(1)
OE	500	500
Penn	50	34(2)
CEI	250(3)	500
TE	250(3)	500
JCP&L	425	405(2)
Met-Ed	250	300(2)
Penelec	250	300(2)
ATSI	50(4)	50

(1) No regulatory approvals, statutory or charter limitations applicable.

(2) Excluding amounts that may be borrowed under the regulated companies money pool.

(3) Borrowing sub-limits for CEI and TE may be increased to up to $500 million by delivering notice to the administrative agent that such borrower has senior unsecured debt ratings of at

least BBB by S&P and Baa2 by Moody s.

(4) The borrowing sub-limit for ATSI may be increased up to $100 million by delivering notice to the administrative agent that ATSI has received regulatory approval to have short-term borrowings up to the same amount.

Under the revolving credit facility, borrowers may request 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 the facility and against the applicable borrower s borrowing sub-limit.

The revolving credit facility 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 June 30, 2010, FirstEnergy s and its subsidiaries debt to total capitalization ratios (as defined under the revolving credit facility) were as follows:

Borrower	
FirstEnergy[1]	61.1%
FES	52.1%
OE	53.4%
Penn	31.3%
CEI	59.3%
TE	59.1%
JCP&L	36.5%
Met-Ed	38.2%
Penelec	53.4%
ATSI	50.3%

(1) As of June 30, 2010, FirstEnergy could issue additional debt of approximately $2.9 billion, or recognize a reduction in equity of

approximately $1.6 billion, and remain within the limitations of the financial covenants required by its revolving credit facility.

The revolving credit facility does not contain provisions that either restrict the ability to borrow or accelerate repayment 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 facility is related to the credit ratings of the company borrowing the funds.

FirstEnergy Money Pools

FirstEnergy s regulated companies also have the ability to borrow from each other and the holding company to meet their short-term working capital requirements. A similar but separate arrangement exists among FirstEnergy s unregulated companies. FESC administers these two money pools and tracks surplus funds of FirstEnergy and the respective regulated and unregulated subsidiaries, as well as proceeds available from bank borrowings. Companies receiving a loan under the money pool agreements must repay the principal amount of the loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from their respective pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in the first six months of 2010 was 0.51% per annum for the regulated companies money pool and 0.59% per annum for the unregulated companies money pool.

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Pollution Control Revenue Bonds

As of June 30, 2010, FirstEnergy s currently payable long-term debt included approximately $1.3 billion (FES $1.2 billion, 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 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 variable interest rate PCRBs were issued by the following banks as of June 30, 2010:

LOC Bank	Aggregate LOC Amount[(2)] *(In millions)*	LOC Termination Date	Reimbursements of LOC Draws Due
CitiBank N.A.	$ 166	June 2014	June 2014
The Bank of Nova Scotia	284	Beginning April 2011	Multiple dates[(3)]
The Royal Bank of Scotland	131	June 2012	6 months
Wachovia Bank	153	March 2014	March 2014
Barclays Bank[(1)]	528	Beginning December 2010	30 days
PNC Bank	70	Beginning November 2010	180 days
Total	$ 1,332		

(1) Supported by 18 participating banks, with no one bank having more than 14% of the total commitment.

(2) Includes approximately $14 million of applicable interest coverage.

(3) Shorter of 6 months or LOC termination date ($155 million) and shorter of one year or LOC termination date ($129 million).

In June 2010, FGCO purchased $15 million fixed rate PCRBs originally issued on its behalf. In April 2010, FGCO purchased approximately $235 million variable rate PCRBs and cancelled $237 million LOC held with KeyBank. Subject to market conditions, FGCO plans to remarket the $15 million PCRBs, as well as the $235 million PCRBs purchased in April, in the near future as market conditions permit.

Long-Term Debt Capacity

As of June 30, 2010, the Ohio Companies and Penn had the aggregate capability to issue approximately $2.3 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 $107 million and $21 million, respectively, as of June 30, 2010. As a result of the indenture provisions, TE cannot incur any additional secured debt. Met-Ed and Penelec had the capability to issue secured debt of approximately $377 million and $343 million, respectively, under provisions of their senior note indentures as of June 30, 2010.

Based upon FGCO s FMB indenture, net earnings and available bondable property additions as of June 30, 2010, FGCO had the capability to issue $2.9 billion of additional FMBs under the terms of that indenture. In June 2009, a new FMB indenture became effective for NGC. Based upon NGC s FMB indenture, net earnings and available bondable property additions, NGC had the capability to issue $294 million of additional FMBs as of June 30, 2010.

FirstEnergy s access to capital markets and costs of financing are influenced by the ratings of its securities. On February 11, 2010, S&P issued a report lowering FirstEnergy s and its subsidiaries credit ratings by one notch, while maintaining its stable outlook. Moody s and Fitch affirmed the ratings and stable outlook of FirstEnergy and its subsidiaries on February 11, 2010. The following table displays FirstEnergy s, FES and the Utilities securities ratings as of June 30, 2010.

Issuer	Senior Secured S&P	Senior Secured Moody s	Senior Secured Fitch	Senior Unsecured S&P	Senior Unsecured Moody s	Senior Unsecured Fitch
FirstEnergy Corp.				BB+	Baa3	BBB
FirstEnergy Solutions				BBB-	Baa2	BBB
Ohio Edison	BBB	A3	BBB+	BBB-	Baa2	BBB
Pennsylvania Power	BBB+	A3	BBB+			
Cleveland Electric Illuminating	BBB	Baa1	BBB	BBB-	Baa3	BBB-
Toledo Edison	BBB	Baa1	BBB			
Jersey Central Power & Light				BBB-	Baa2	BBB+
Metropolitan Edison	BBB	A3	BBB+	BBB-	Baa2	BBB
Pennsylvania Electric	BBB	A3	BBB+	BBB-	Baa2	BBB
ATSI				BBB-	Baa1	

Changes in Cash Position

As of June 30, 2010, FirstEnergy had $281 million in cash and cash equivalents compared to $874 million as of December 31, 2009. As of June 30, 2010 and December 31, 2009, FirstEnergy had approximately $10 million and $12 million, respectively, of restricted cash included in other current assets on the Consolidated Balance Sheet.

During the first six months of 2010, FirstEnergy received $655 million of cash dividends from its subsidiaries and paid $335 million in cash dividends to common shareholders.

Cash Flows From Operating Activities

FirstEnergy s consolidated net cash from operating activities is provided primarily by its competitive energy services and energy delivery services businesses (see Results of Operations above). Net cash provided from operating activities decreased by $244 million during the first six months of 2010 compared to the comparable period in 2009, as summarized in the following table:

Operating Cash Flows	Six Months Ended June 30 2010	Six Months Ended June 30 2009	Increase (Decrease)
	(In millions)		
Net income	$ 405	$ 523	$ (118)
Non-cash charges and other adjustments	789	719	70
Working Capital and other	(336)	(140)	(196)
	$ 858	$ 1,102	$ (244)

The increase in non-cash charges and other adjustments is primarily due to higher deferred income taxes and investment tax credits ($90 million) and higher non-cash retirement benefit expenses ($66 million) recognized in the first six months of 2010, partially offset by lower net amortization of regulatory assets ($133 million), including CEI s $216 million regulatory asset impairment recorded during the first quarter of 2009. The change in working capital and other charges primarily resulted from a $111 million decrease in cash collateral received, a $98 million decrease in prepayments and other current assets, and a $43 million increase in accrued taxes, partially offset by a $188 million increase in receivables and a $23 million increase in materials and supplies. The change in prepayments and accrued taxes primarily relates to the timing of income tax payments.

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Cash Flows From Financing Activities

In the first six months of 2010, cash used for financing activities was $484 million compared to cash provided from financing activities of $426 million in the first six months of 2009. The decrease was primarily due to new debt issuances in 2009 and the repayment of short-term borrowings in 2010, partially offset by decreased long-term debt redemptions in 2010. The following table summarizes security issuances (net of any discounts) and redemptions:

Securities Issued or Redeemed	Six Months Ended June 30 2010		Six Months Ended June 30 2009	
	(In millions)			
New Issues				
First mortgage bonds				100
Pollution control notes				682
Senior secured notes				297
Unsecured Notes				600
	$		$	1,679
Redemptions				
Pollution control notes		251		682
Senior secured notes		55		46
Unsecured notes		100		153
	$	406	$	881
Short-term borrowings, net	$	281	$	

Cash Flows From Investing Activities

Net cash flows used in investing activities resulted primarily from property additions. Additions for the energy delivery services segment primarily represent expenditures related to transmission and distribution facilities. Capital spending by the competitive energy services segment is principally generation-related. The following table summarizes investing activities for the first six months of 2010 and 2009 by business segment:

Summary of Cash Flows Provided from (Used for) Investing Activities		Property Additions		Investments		Other		Total
				(In millions)				
Sources (Uses)								
Six Months Ended June 30, 2010								
Energy delivery services	$	(338)	$	87	$	(20)	$	(271)
Competitive energy services		(605)		(11)		(1)		(617)
Other		(10)		(3)				(13)
Inter-Segment reconciling items		(44)		(22)				(66)
Total	$	(997)	$	51	$	(21)	$	(967)

Six Months Ended June 30, 2009								
Energy delivery services	$	(343)	$	48	$	(23)	$	(318)
Competitive energy services		(669)		2		(22)		(689)
Other		(119)		(7)		(3)		(129)
Inter-Segment reconciling items		(12)		(25)				(37)
Total	$	(1,143)	$	18	$	(48)	$	(1,173)

Net cash used for investing activities in the first six months of 2010 decreased by $206 million compared to the first six months of 2009. The decrease was principally due to a $146 million decrease in property additions, which reflects lower AQC system expenditures, and cash proceeds of approximately $116 million from the sale of assets, partially offset by $105 million relating to the acquisition of customer intangible assets.

During the remaining two quarters of 2010, capital requirements for property additions and capital leases are expected to be approximately $918 million, including approximately $155 million for nuclear fuel. These cash requirements are expected to be satisfied from a combination of internal cash and short-term credit arrangements.

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.

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As of June 30, 2010, FirstEnergy s maximum exposure to potential future payments under outstanding guarantees and other assurances approximated $3.9 billion, as summarized below:

Guarantees and Other Assurances	Maximum Exposure (In millions)
FirstEnergy Guarantees on Behalf of its Subsidiaries	
Energy and Energy-Related Contracts[1]	$ 300
LOC (long-term debt) Interest coverage[2]	6
FirstEnergy guarantee of OVEC obligations	300
Other[3]	294
	900
Subsidiaries Guarantees	
Energy and Energy-Related Contracts	54
LOC (long-term debt) Interest coverage[2]	4
FES guarantee of NGC s nuclear property insurance	70
FES guarantee of FGCO s sale and leaseback obligations	2,413
Other	2
	2,543
Surety Bonds	90
LOC (long-term debt) Interest coverage[2]	3
LOC (non-debt)[4][5]	372
	465
Total Guarantees and Other Assurances	$ 3,908

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

(2) Reflects the interest coverage portion of LOCs issued in support of floating rate PCRBs with various maturities. The principal amount

of floating-rate PCRBs of $1.3 billion is reflected in currently payable long-term debt on FirstEnergy s consolidated balance sheets.

(3) Includes guarantees of $80 million for nuclear decommissioning funding assurances, which has been reduced to $15 million in July 2010, and $161 million supporting OE s sale and leaseback arrangement.

(4) Includes $193 million issued for various terms pursuant to LOC capacity available under FirstEnergy s revolving credit facility.

(5) Includes approximately $135 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by OE and $44 million pledged in connection with the sale and leaseback of Perry by OE.

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 FirstEnergy s 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 a LOC or accelerated payments may be required of the subsidiary. As of June 30, 2010, FirstEnergy s maximum exposure under these collateral provisions was $451 million, as shown below:

Collateral Provisions	FES	Utilities	Total
		(In millions)	
Credit rating downgrade to below investment grade	$ 314	$ 17	$ 331
Acceleration of payment or funding obligation	15	68	83
Material adverse event	37		37
Total	$ 366	$ 85	$ 451

Stress case conditions of a credit rating downgrade or material adverse event and hypothetical adverse price movements in the underlying commodity markets would increase the total potential amount to $609 million, consisting of $56 million due to material adverse event contractual clauses, $83 million due to an acceleration of payment or funding obligation, and $470 million due to a below investment grade credit rating.

Most of FirstEnergy s surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related guarantees of $90 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, FES contracts, including power contracts with affiliates awarded through competitive bidding processes, typically contain margining provisions which require the posting of cash or LOCs in amounts determined by future power price movements. Based on FES power portfolio as of June 30, 2010, and forward prices as of that date, FES has posted collateral of $245 million. Under a hypothetical adverse change in forward prices (95% confidence level change in forward prices over a one year time horizon), FES would be required to post an additional $107 million. Depending on the volume of forward contracts and future price movements, FES could be required to post higher amounts for margining.

In connection with FES obligations to post and maintain collateral under the two-year PSA entered into by FES and the Ohio Companies following the CBP auction on May 13-14, 2009, NGC entered into a Surplus Margin Guaranty in an amount up to $500 million. The Surplus Margin Guaranty is secured by an NGC FMB issued in favor of the Ohio Companies.

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 will have claims against each of FES, FGCO and NGC regardless of whether their primary obligor is FES, FGCO or NGC.

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, is $1.6 billion as of June 30, 2010.

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 and market risks resulting from the fluctuation of interest rates and commodity prices associated with electricity, energy transmission, natural gas, coal, nuclear fuel and emission allowances. To manage the volatility relating to these exposures, FirstEnergy uses a variety of non-derivative and derivative instruments, including forward contracts, options, futures contracts and swaps. The derivatives are used principally for hedging purposes.

The valuation of derivative contracts is based on observable market information to the extent that such information is available. In cases where such information is not available, FirstEnergy relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. FirstEnergy uses these results to develop estimates of fair value for financial reporting purposes and for internal management decision making (see Note 3 to the consolidated financial statements). Sources of information for the valuation of commodity derivative contracts as of June 30, 2010 are summarized by year in the following table:

Source of Information- Fair Value by Contract Year	**2010**	**2011**	**2012**	**2013**	**2014**	**Thereafter**	**Total**
				(In millions)			
Prices actively quoted[1]	$ (5)	$	$	$	$	$	$ (5)
Other external sources[2]	(322)	(332)	(147)	(34)	4	(17)	(848)
Prices based on models					(9)	138	129
Total[3]	$ (327)	$ (332)	$ (147)	$ (34)	$ (5)	$ 121	$ (724)

(1) Represents exchange traded NYMEX futures and options.

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

(3) Includes $547 million in non-hedge commodity derivative contracts that are primarily related to NUG contracts. NUG contracts are subject to regulatory accounting and do not impact earnings.

FirstEnergy performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. Based on derivative contracts held as of June 30, 2010, an adverse 10% change in commodity prices would decrease net income by approximately $9 million ($6 million net of tax) during the next 12 months.

Interest Rate Swap Agreements Fair Value Hedges

FirstEnergy uses 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 derivatives are 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. In May of 2010, FirstEnergy terminated fixed-for-floating interest rate swap agreements with a notional value of $3.15 billion, which resulted in cash proceeds of $43.1 million. These proceeds will be amortized to earnings over the life of the underlying debt.

Effective June 1, 2010, FirstEnergy executed multiple fixed-for-floating interest rate swap agreements with a combined notional value of $3.2 billion, which essentially replaced the swap agreements terminated in May of 2010. As of June 30, 2010, the debt underlying the $3.2 billion outstanding notional amount of interest rate swaps had a weighted average fixed interest rate of 6%, which the swaps have converted to a current weighted average variable rate of 4%. A hypothetical 10% increase in the interest rates associated with variable-rate debt would decrease net income by less than $1 million for the three and six months ended June 30, 2010.

On July 16, 2010, FirstEnergy terminated these fixed-for-floating interest rate swap agreements with a notional value of $3.2 billion, which resulted in cash proceeds of $83.6 million. These proceeds will be amortized to earnings over the life of the underlying debt. While FirstEnergy currently does not have any interest rate swaps outstanding, costs associated with entering into future swap transactions may be increased as a result of the recent passage of the Dodd-Frank Wall Street Reform and Consumer Protection Act, which requires increased regulation of swaps, swap dealers and major swap participants.

Equity Price Risk

FirstEnergy provides a noncontributory qualified defined benefit pension plan that covers substantially all of its employees and non-qualified pension plans that cover certain employees. The plan provides defined benefits based on years of service and compensation levels. FirstEnergy also provides health care benefits (which include certain employee contributions, deductibles and co-payments) upon retirement to employees hired prior to January 1, 2005, their dependents, and under certain circumstances, their survivors. The benefit plan assets and obligations are remeasured annually using a December 31 measurement date or as significant triggering events occur. As of June 30, 2010, approximately 53% of the pension plan is invested in equity securities and 47% is invested in fixed income securities and the plan is currently underfunded. A decline in the value of FirstEnergy s pension plans could result in additional funding requirements. FirstEnergy currently estimates that additional cash contributions will be required beginning in 2012. The overall actual investment result during 2009 was a gain of 13.6% compared to an assumed 9% positive return.

Nuclear decommissioning trust funds have been established to satisfy NGC s and the Utilities nuclear decommissioning obligations. As of June 30, 2010, approximately 15% of the funds were invested in equity securities and 85% were invested in fixed income securities, with limitations related to concentration and investment grade ratings. The equity securities are carried at their market value of approximately $275 million as of June 30, 2010. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $28 million reduction in fair value as of June 30, 2010. 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 nuclear decommissioning trusts as other-than-temporary impairments. A decline in the value of FirstEnergy s nuclear decommissioning trusts could result in additional funding requirements. As of June 30, 2010, $4 million was contributed to the OE and TE nuclear decommissioning trusts to comply with requirements under certain sale-leaseback transactions in which OE and TE continue as lessees, and $3 million was contributed to the JCP&L and Pennsylvania nuclear decommissioning trusts to comply with regulatory requirements. FirstEnergy continues to evaluate the status of its funding obligations for the decommissioning of these nuclear facilities and does not expect to make additional cash contributions to the nuclear decommissioning trusts for the remainder of 2010 other than those to the JCP&L and Pennsylvania Companies nuclear decommissioning trusts due to regulatory requirements.

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 June 30, 2010, the largest credit concentration was with AEP, which is currently rated investment grade, representing 7.85% of FirstEnergy s total approved credit risk.

OUTLOOK

State Regulatory Matters

FirstEnergy and the utilities prepare their consolidated financial statements in accordance with the authoritative guidance for accounting for certain types of regulation. Under this guidance, regulatory assets represent incurred or accrued costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates. The following table provides the balance of regulatory assets by Company as of June 30, 2010 and December 31, 2009, and changes during the six months then ended:

Regulatory Assets	June 30, 2010	December 31, 2009	Increase (Decrease)
		(In millions)	
OE	$ 423	$ 465	$ (42)
CEI	468	546	(78)
TE	82	70	12
JCP&L	801	888	(87)
Met-Ed	385	357	28
Penelec	139	9	130
Other	15	21	(6)

Total	$ 2,313	$ 2,356	$ (43)

The following table provides information about the composition of regulatory assets as of June 30, 2010 and December 31, 2009 and the changes during the six months then ended:

Regulatory Assets by Source	June 30, 2010	December 31, 2009	Increase (Decrease)
		(In millions)	
Regulatory transition costs	$ 1,153	$ 1,100	$ 53
Customer shopping incentives	74	154	(80)
Customer receivables for future income taxes	332	329	3
Loss on reacquired debt	49	51	(2)
Employee postretirement benefits	19	23	(4)
Nuclear decommissioning, decontamination and spent fuel disposal costs	(152)	(162)	10
Asset removal costs	(235)	(231)	(4)
MISO/PJM transmission costs	156	148	8
Fuel costs	385	369	16
Distribution costs	408	482	(74)
Other	124	93	31
Total	$ 2,313	$ 2,356	$ (43)

Regulatory assets that do not earn a current return totaled approximately $181 million as of June 30, 2010 (JCP&L $43 million, Met-Ed $131 million, Penelec $3 million and CEI $4 million). Regulatory assets not earning a current return (primarily for certain regulatory transition costs and employee postretirement benefits) are expected to be recovered by 2014 for JCP&L and by 2020 for Met-Ed and Penelec.

Reliability Initiatives

Federally-enforceable mandatory reliability standards apply to the bulk power system and impose certain operating, record-keeping and reporting requirements on the Utilities and ATSI. The NERC has delegated day-to-day implementation and enforcement of these reliability standards to eight regional entities, including Reliability*First* Corporation. All of FirstEnergy s facilities are located within the Reliability*First* region. FirstEnergy actively participates in the NERC and Reliability*First* 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 Reliability*First* Corporation.

FirstEnergy believes that it is in compliance with all currently-effective and enforceable reliability standards. Nevertheless, FirstEnergy also believes that the NERC, Reliability*First* and the FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. The financial impact of complying with 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 new reliability standards be recovered in rates. Still, 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.

Ohio

The Ohio Companies operate under an Amended ESP, which expires on May 31, 2011, and provides for generation supplied through a CBP. The Amended ESP also allows the Ohio Companies to collect a delivery service improvement rider (Rider DSI) at an overall average rate of $0.002 per KWH for the period of April 1, 2009 through December 31, 2011. The Ohio Companies currently purchase generation at the average wholesale rate of a CBP conducted in May 2009. FES is one of the suppliers to the Ohio Companies through the CBP. The PUCO approved a $136.6 million distribution rate increase for the Ohio Companies in January 2009, which went into effect on January 23, 2009 for OE ($68.9 million) and TE ($38.5 million) and on May 1, 2009 for CEI ($29.2 million). As one element of the Amended ESP, the Ohio Companies agreed not to seek an additional base distribution rate increase, subject to certain exceptions, that would be effective before January 1, 2012. Applications for rehearing of the PUCO order in the distribution case were filed by the Ohio Companies and one other party. The Ohio Companies raised numerous issues in their application for rehearing related to rate recovery of certain expenses, recovery of line extension costs, the level of rate of return and the amount of general plant balances. The PUCO has not yet issued a substantive Entry on Rehearing.

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On October 20, 2009, the Ohio Companies filed an MRO to procure, through a CBP, generation supply for customers who do not shop with an alternative supplier for the period beginning June 1, 2011. The CBP would be similar, in all material respects, to the CBP conducted in May 2009 in that it would procure energy, capacity and certain transmission services on a slice of system basis. However, unlike the May 2009 CBP, the MRO would include multiple bidding sessions and multiple products with different delivery periods for generation supply designed to reduce potential volatility and supplier risk and encourage bidder participation. A technical conference and hearings were held in 2009 and the matter has been fully briefed. Pursuant to SB221, the PUCO has 90 days from the date of the application to determine whether the MRO meets certain statutory requirements. Although the Ohio Companies requested a PUCO determination by January 18, 2010, on February 3, 2010, the PUCO announced that its determination would be delayed. Under a determination that such statutory requirements are met, and to the extent the ESP described below has not been implemented, the Ohio Companies would expect to implement the MRO.

On March 23, 2010, the Ohio Companies filed an application for a new ESP, which if approved by the PUCO, would go into effect on June 1, 2011 and conclude on May 31, 2014. Attached to the application was a Stipulation and Recommendation signed by the Ohio Companies, the Staff of the PUCO, and an additional fourteen parties signing as Signatory Parties, with two additional parties agreeing not to oppose the adoption of the Stipulation. The material terms of the Stipulation include a CBP similar to the one used in May 2009 and the one proposed in the October 2009 MRO filing; a 6% generation discount to certain low-income customers provided by the Ohio Companies through a bilateral wholesale contract with FES; no increase in base distribution rates through May 31, 2014; and a new distribution rider, Delivery Capital Recovery Rider (Rider DCR), to recover a return of, and on, capital investments in the delivery system. This Rider substitutes for Rider DSI which terminates by its own terms. The Ohio Companies also agree not to collect certain amounts associated with RTEP and administrative costs associated with the move to PJM. Many of the existing riders approved in the previous ESP remain in effect, some with modifications. The new ESP also requests the resolution of current proceedings pending at the PUCO regarding corporate separation, elements of the smart grid proceeding and the move to PJM. The evidentiary hearing began on April 20, 2010, at the PUCO. The Stipulation requested a decision by the PUCO by May 5, 2010. On April 28, 2010, the PUCO Chairman issued a statement that the PUCO would not issue a decision on May 5, 2010, and would take additional time to review the case record. FirstEnergy recorded approximately $39.5 million of regulatory asset impairments and expenses related to the ESP. On May 12, 2010 a supplemental stipulation was filed that added two additional parties to the Stipulation, namely the City of Akron, Ohio and Council for Smaller Enterprises, to provide additional energy efficiency benefits. Pursuant to a PUCO Entry, a hearing was held on June 21, 2010 to consider the estimated bill impacts arising from the proposed ESP, and testimony was provided in support of the supplemental stipulation. On July 22, 2010, a second supplemental stipulation was filed that, among other provisions and if approved, would provide a commitment that retail customers of the Ohio Companies will not pay certain costs related to the companies integration into PJM, a regional transmission organization, for the longer of the five year period from June 1, 2011 through May 31, 2016 or when the amount of costs avoided by customers for certain types of products totals $360 million, and establishes a $12 million fund to assist low income customers over the term of the ESP. Additional parties signing or not opposing the second supplemental stipulation include Northeast Ohio Public Energy Council (NOPEC), Northwest Ohio Aggregation Coalition (NOAC), Environmental Law and Policy Center and a number of low income community agencies. A hearing was held on the second supplemental stipulation on July 29, 2010. The matter is awaiting decision from the PUCO**.**

Under the provisions of SB221, the Ohio Companies are required to implement energy efficiency programs that will achieve a total annual energy savings equivalent of approximately 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 are also required to reduce peak demand in 2009 by 1%, with an additional 0.75% reduction each year thereafter through 2018. The PUCO may amend these benchmarks in certain, limited circumstances, and the Ohio Companies filed an application with the PUCO seeking such amendments. On January 7, 2010, the PUCO amended the Ohio Companies 2009 energy efficiency benchmarks to zero, contingent upon the Ohio Companies meeting the revised benchmarks in a period of not more than three years. On March 10, 2010, the PUCO found that the Ohio Companies peak demand reduction programs complied with PUCO rules.

On December 15, 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. On March 8, 2010, the Ohio Companies filed their 2009 Status Update Report with the PUCO in which they indicated compliance with the 2009 statutory energy efficiency and peak demand benchmarks as those benchmarks were amended as described above. The Ohio Companies expect that all costs associated with compliance will be recoverable from customers. The Ohio Companies three year portfolio plan is still awaiting decision from the PUCO. The plan has yet to be approved by the PUCO, which is delaying the launch of the programs described in the plan. Without such approval, the Ohio Companies compliance with 2010 benchmarks is jeopardized and if not approved soon may require the Ohio Companies to seek an amendment to their annual benchmark requirements for 2010. Failure to comply with the benchmarks or to obtain such an amendment may subject the Companies to an assessment by the PUCO of a forfeiture.

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 serve in 2009. In August and October 2009, the Ohio Companies conducted RFPs to secure RECs. The RFPs sought RECs, including solar RECs and RECs generated in Ohio in order to meet the Ohio Companies alternative energy requirements as set forth in SB221 for 2009, 2010 and 2011. The RECs acquired through these two RFPs will be used to help meet the renewable energy requirements established under SB221 for 2009, 2010 and 2011. On March 10, 2010, the PUCO found that there was an insufficient quantity of solar energy resources reasonably available in the market. The PUCO reduced the Ohio Companies aggregate 2009 benchmark to the level of solar RECs the Ohio Companies acquired through their 2009 RFP processes, provided the Companies 2010 alternative energy requirements be increased to include the shortfall for the 2009 solar REC benchmark. On April 15, 2010, the Ohio Companies and FES (due to its status as an electric service company in Ohio) filed compliance reports with the PUCO setting forth how they individually satisfied the alternative energy requirements in SB221 for 2009. FES also applied for a force majeure determination from the PUCO regarding a portion of their compliance with the 2009 solar energy resource benchmark, which application is still pending. On July 1, 2010, the Ohio Companies announced their intent to conduct an RFP in 2010 to secure RECs and solar RECs needed to meet the Ohio Companies alternative energy requirements as set forth in SB221. RFP bids are due August 3, 2010 and contracts are expected to be signed the week of August 9, 2010.

On February 12, 2010, OE and CEI filed an application with the PUCO to establish a new credit for all-electric customers. On March 3, 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 on March 17, 2010. On April 15, 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 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 on May 21, 2010. The Ohio Companies also filed on May 14, 2010 an application for rehearing of the Second Entry on Rehearing, which was granted for purposes of further consideration on June 9, 2010. No hearing has been scheduled in this matter.

As noted above in Note 8, FirstEnergy, CEI and OE filed a motion to dismiss a class action lawsuit related to the PUCO approved reduction of a discount that had previously been in place for residential customers with electric heating, electric water heating, or load management systems. The court has not yet ruled on that motion to dismiss.

Pennsylvania

Met-Ed and Penelec purchase a portion of their POLR and default service requirements from FES through a fixed-price partial requirements wholesale power sales agreement. The agreement allows Met-Ed and Penelec to sell the output of NUG energy to the market and requires FES to provide energy at fixed prices to replace any NUG energy sold to the extent needed for Met-Ed and Penelec to satisfy their POLR and default service obligations.

Met-Ed and Penelec filed with the PPUC a generation procurement plan covering the period January 1, 2011 through May 31, 2013. The plan is designed to provide adequate and reliable service via a prudent mix of long-term, short-term and spot market generation supply, as required by Act 129, with a staggered procurement schedule, which varies by customer class, through the use of a descending clock auction. On August 12, 2009, Met-Ed and Penelec filed a settlement agreement with the PPUC for the generation procurement plan, reflecting the settlement on all but two reserved issues. On November 6, 2009, the PPUC entered an Order approving the settlement and finding in favor of Met-Ed and Penelec on the two reserved issues. Generation procurement began in January 2010.

On February 8, 2010, Penn filed a Petition for Approval of its Default Service Plan for the period June 1, 2011 through May 31, 2013. The parties to the proceeding have reached a settlement on all issues and filed a joint petition to approve the settlement agreement in July 2010. The PPUC is required to issue an order on the plan no later than November 8, 2010. If approved, procurement under the plan is expected to begin January 2011.

The PPUC adopted a Motion on January 28, 2010 and subsequently entered an Order on March 3, 2010 which denies the recovery of marginal transmission losses through the TSC rider for the period of June 1, 2007 through March 31, 2008, and directs Met-Ed and Penelec to submit a new tariff or tariff supplement reflecting the removal of marginal transmission losses from the TSC, and instructs 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. On March 18, 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 marginal transmission loss costs. By Order entered March 25, 2010, the PPUC granted the requested stay until December 31, 2010. Pursuant to the PPUC s order, Met-Ed and Penelec filed the plan to establish separate accounts for marginal transmission loss revenues and related interest and carrying charges and the plan for the use of these funds to mitigate future generation rate increases commencing January 1, 2011. The PPUC approved this plan June 7, 2010.

On April 1, 2010, Met-Ed and Penelec filed a Petition for Review with the Commonwealth Court of Pennsylvania appealing the PPUC s March 3, 2010 Order. Although the ultimate outcome of this matter cannot be determined at this time, it is the belief of Met-Ed and Penelec that they should prevail in the appeal and therefore expect to fully recover the approximately $199.7 million ($158.5 million for Met-Ed and $41.2 million for Penelec) in marginal transmission losses for the period prior to January 1, 2011. On April 2, 2010, Met-Ed and Penelec filed a Response to the PPUC s March 3, 2010 Order requesting approval of procedures to establish separate accounts to track all marginal transmission loss revenues and related interest and the use of those funds to mitigate future generation rate increases commencing January 1, 2011, and the PPUC entered an Order on June 7, 2010, granting Met-Ed s and Penelec s request. On July 9 2010, Met-Ed and Penelec filed their briefs with the Commonwealth Court of Pennsylvania. The Office of Small Business Advocate filed its brief on July 9, 2010. The PPUC s brief is due to be filed in August 2010.

On May 20, 2010, the PPUC approved Met-Ed s and Penelec s annual updates to their TSC rider for the period June 1, 2010 through 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 TSC for Met-Ed s customers increased to be fully recovered by December 31, 2010.

Act 129 was enacted 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. The PPUC entered an Order on February 26, 2010 approving the Pennsylvania Companies EE&C Plans and the tariff rider with rates effective March 1, 2010.

Met-Ed, Penelec and Penn jointly filed a Smart Meter Technology Procurement and Installation Plan with the PPUC. This plan proposes a 24-month assessment period in which the Pennsylvania Companies 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 at approximately $29.5 million, which the Pennsylvania Companies, in their plan, proposed to recover through an automatic adjustment clause. The ALJ s Initial Decision approved the Smart Meter Plan as modified by the ALJ, including: ensuring that the smart meters to be deployed include the capabilities listed in the PPUC s Implementation Order; eliminating the provision of interest in the 1307(e) reconciliation; providing for the recovery of reasonable and prudent costs minus resulting savings from installation and use of smart meters; and reflecting that administrative start-up costs be expensed and the costs incurred for research and development in the assessment period be capitalized. On April 15, 2010, the PPUC adopted a Motion by Chairman Cawley that modified the ALJ s initial decision, and decided various issues regarding the Smart Meter Implementation Plan for the Pennsylvania Companies. The PPUC entered its Order on June 9, 2010, consistent with the Chairman s Motion. On June 24, 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 roll smart meter costs into base rates.

Legislation addressing rate mitigation and the expiration of rate caps was introduced in the legislative session that ended in 2008; several bills addressing these issues were introduced in the 2009 legislative session. The final form and impact of such legislation is uncertain.

By Tentative Order entered September 17, 2009, the PPUC provided for an additional 30-day comment period on whether the 1998 Restructuring Settlement 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 above accounting method utilized by Met-Ed and Penelec. Met-Ed and Penelec are awaiting further action by the PPUC.

New Jersey

JCP&L is permitted to defer for future collection from customers the amounts by which its costs of supplying BGS to non-shopping customers, costs incurred under NUG agreements, and certain other stranded costs, exceed amounts collected through BGS and NUGC rates and market sales of NUG energy and capacity. As of June 30, 2010, the accumulated deferred cost balance totaled approximately $81 million. To better align the recovery of expected costs, on July 26, 2010, JCP&L filed a request to decrease the amount recovered for the costs incurred under the NUG agreements by $180 million annually. If approved as filed, the change would not go into effect until January 1, 2011.

In accordance with an April 28, 2004 NJBPU order, JCP&L filed testimony on June 7, 2004, supporting continuation of the current level and duration of the funding of TMI-2 decommissioning costs by New Jersey customers without a reduction, termination or capping of the funding. On September 30, 2004, JCP&L filed an updated TMI-2 decommissioning study. This study resulted in an updated total decommissioning cost estimate of $729 million (in 2003 dollars) compared to the estimated $528 million (in 2003 dollars) from the prior 1995 decommissioning study. The DPA filed comments on February 28, 2005 requesting that decommissioning funding be suspended. On March 18, 2005, JCP&L filed a response to those comments. JCP&L responded to additional NJBPU staff discovery requests in May and November 2007 and also submitted comments in the proceeding in November 2007. A schedule for further NJBPU proceedings has not yet been set. On March 13, 2009, JCP&L filed its annual SBC Petition with the NJBPU that includes a request for a reduction in the level of recovery of TMI-2 decommissioning costs based on an updated TMI-2 decommissioning cost analysis dated January 2009 estimated at $736 million (in 2003 dollars). This matter is currently pending before the NJBPU.

New Jersey statutes require that the state periodically undertake a planning process, known as the EMP, to address energy related issues including energy security, economic growth, and environmental impact. The NJBPU adopted an order establishing the general process and contents of specific EMP plans that must be filed by New Jersey electric and gas utilities in order to achieve the goals of the EMP. On April 16, 2010, the NJBPU issued an order indefinitely suspending the requirement of New Jersey utilities to submit Utility Master Plans until such time as the status of the EMP has been made clear. At this time, FirstEnergy and JCP&L cannot determine the impact, if any, the EMP may have on their operations.

In support of former New Jersey Governor Corzine s Economic Assistance and Recovery Plan, JCP&L announced a proposal to spend approximately $98 million on infrastructure and energy efficiency projects in 2009. Under the proposal, an estimated $40 million would be spent on infrastructure projects, including substation upgrades, new transformers, distribution line re-closers and automated breaker operations. In addition, approximately $34 million would be spent implementing new demand response programs as well as expanding on existing programs. Another $11 million would be spent on energy efficiency, specifically replacing transformers and capacitor control systems and installing new LED street lights. The remaining $13 million would be spent on energy efficiency programs that would complement those currently being offered. The project relating to expansion of the existing demand response programs was approved by the NJBPU on August 19, 2009, and implementation began in 2009. Approval for the project related to energy efficiency programs intended to complement those currently being offered was denied by the NJBPU on December 1, 2009. On July 6, 2010, the January 30, 2009 petition directed to infrastructure investment which had been pending before the NJBPU was withdrawn by JCP&L. Implementation of the remaining projects is dependent upon resolution of regulatory issues including recovery of the costs associated with the proposal.

FERC Matters

PJM Transmission Rate

On April 19, 2007, the 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, the 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, referred to as DFAX , generally referred to as a beneficiary pays approach to allocating the cost of high voltage transmission facilities. The FERC found that PJM s current beneficiary-pays cost allocation methodology was not sufficiently detailed and, in a related order that also was issued on April 19, 2007, directed that hearings be held for the purpose of establishing a just and reasonable cost allocation methodology for inclusion in PJM s tariff. FERC ultimately issued an order approving use of the beneficiary pays method of cost allocation for transmission facilities included in the PJM regional plan that operate below 500 kV.

The FERC s April 19, 2007 order was appealed to the U.S. Court of Appeals for the Seventh Circuit, which issued a decision on August 6, 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 facilities on a load ratio share basis and, based on this finding, remanded the rate design issue back to FERC.

In an order dated January 21, 2010, FERC set the matter for paper hearings meaning that FERC called for parties to submit comments or written testimony 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 within 45 days, and reply comments 30 days later. 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 eastern utilities in PJM bearing the majority of their 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. Certain eastern utilities and their state commissions supported continued socialization of these costs on a load ratio share basis. FERC is not expected to act before the fourth quarter of 2010.

RTO Consolidation

FERC issued an order approving, subject to certain future compliance filings, ATSI s move to PJM. This allows FirstEnergy to consolidate its transmission assets and operations into PJM. Currently, FirstEnergy s transmission assets and operations are divided between PJM and MISO. The consolidation will make the transmission assets that are part of ATSI, whose footprint includes the Ohio Companies and Penn, part of PJM. Most of FirstEnergy s transmission assets in Pennsylvania and all of the transmission assets in New Jersey already operate as a part of PJM. FERC approved FirstEnergy s proposal to use a Fixed Resource Requirement Plan (FRR Plan) to obtain capacity to satisfy the PJM capacity requirements for the 2011-12 and 2012-13 delivery years.

In December 2009, ATSI executed the PJM Consolidated Transmission Owners Agreement and the Ohio Companies and Penn executed the PJM Operating Agreement and the PJM Reliability Assurance Agreement. Execution of these agreements committed ATSI and the Ohio Companies and Penn s load to moving into PJM on the schedule described in the application and approved in the FERC Order.

FirstEnergy successfully conducted the FRR auctions on March 19, and participated in the PJM base residual auction for the 2013 delivery year, thereby obtaining the capacity necessary for its ATSI footprint to meet PJM s capacity requirements. FirstEnergy expects to integrate into PJM effective June 1, 2011.

On September 4, 2009, the PUCO opened a case to take comments from Ohio s stakeholders regarding the RTO consolidation. Several parties have intervened in the regulatory dockets at the FERC and at the PUCO. Certain interveners have commented and protested particular elements of the proposed RTO consolidation, including an exit fee to MISO, integration costs to PJM, and cost-allocations of future transmission upgrades in PJM and MISO.

MISO Complaints Versus PJM

On March 9, 2010, MISO filed two complaints against PJM with FERC under Sections 206, 306 and 309 of the FPA alleging violations of the MISO/PJM Joint Operating Agreement (JOA). In Docket EL 10-46-000, the complaint alleges that PJM erroneously calculated charges to MISO for market-to-market settlements made from 2005 to 2009 pursuant to the congestion management provisions of the JOA. The MISO seeks approximately $130 million plus interest to correct for resultant net underpayments from PJM to MISO. In Docket No.EL10-45-000, MISO alleges that by failing to account for the market flows from 34 PJM generators over the period from 2007-2009, PJM underpaid MISO by a total of roughly $75 million including interest. For the period from 2005-2007, MISO claimed an underpayment by PJM of at least $12 million plus interest. MISO also claimed that PJM failed to maintain required records necessary to calculate underbilling for the 2005-2007 billing.

In the second complaint, MISO alleged that PJM has refused to comply with provisions of the JOA requiring market-to-market dispatch since 2009, and is improperly demanding repayment of redispatch payments previously made to MISO. PJM filed its answers to the complaints on April 12, 2010, opposing the relief sought by MISO.

In addition, on April 12, 2010, PJM filed a complaint with FERC pursuant to Section 206, 306, and 309 alleging that MISO is violating the JOA with PJM by initiating market-to-market coordination and financial settlements for substitute (proxy) reciprocal coordinated flowgates between MISO and PJM. PJM claims that the JOA does not permit MISO to initiate market-to-market settlements using proxy flowgates in lieu of designated reciprocal coordinated flowgates. This complaint addresses substantially the same issues as the second MISO complaint, in which MISO argues that the use of proxy flowgates is permitted by agreement of the RTOs and operating practice. Each party filed a complaint in order to ensure their right to claim refunds, if any, if successful in their arguments at FERC.

On June 29, 2010, FERC issued an order consolidating the cases and establishing settlement judge procedures. If the settlement process is unsuccessful, the cases will proceed to evidentiary hearings. FirstEnergy is unable to predict the outcome of this matter.

MISO Multi-Value Project Rule Proposal

On July 15, 2010, MISO and certain MISO transmission owners jointly filed with the FERC their proposed cost allocation methodology for new transmission projects. If approved, so-called Multi Value Projects (MVPs) transmission projects that have a regional impact and are part of a regional plan will have a 100% regional allocation of costs under the proposed methodology. If approved by FERC, MISO s proposal is expected to permit the allocation of the costs of large transmission projects designed to integrate wind from the upper Midwest across the entire MISO. MISO has requested a FERC response to the filing by the FERC s December open meeting, but an effective date for its proposal of July 16, 2011. 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.

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 NO_X emissions regulations under the CAA. FirstEnergy complies with SO_2 and NOx reduction requirements under the CAA and State Implementation Plan(s) under the CAA (SIPs) 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.

The Sammis, Burger, Eastlake and Mansfield coal-fired plants are operated under a consent decree with the EPA and DOJ that requires reductions of NO_X and SO_2 emissions through the installation of pollution control devices or repowering. OE and Penn are subject to stipulated penalties for failure to install and operate such pollution controls or complete repowering in accordance with that agreement. Capital expenditures necessary to complete requirements of the consent decree, including repowering Burger Units 4 and 5 for biomass fuel combustion, are currently estimated to be approximately $399 million for 2010-2012.

In 2007, PennFuture filed a citizen suit under the CAA, alleging violations of air pollution laws at the Bruce Mansfield Plant, including opacity limitations, in the U.S. District Court for the Western District of Pennsylvania. In July 2008, three additional complaints were filed against FGCO in the U.S. District Court for the Western District of Pennsylvania also seeking damages based on 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. A settlement was reached with PennFuture. FGCO believes the claims of the remaining plaintiffs are without merit and intends to defend itself against the allegations made in those three complaints.

The states of New Jersey and Connecticut filed CAA citizen suits in 2007 alleging NSR violations at the Portland Generation Station against Reliant (the current owner and operator), Sithe Energy (the purchaser of the Portland Station from Met-Ed in 1999), GPU and Met-Ed. Specifically, these suits allege that modifications at Portland Units 1 and 2 occurred between 1980 and 2005 without preconstruction NSR or permitting under 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.

In January 2009, the EPA issued a NOV to Reliant alleging NSR violations at the Portland Generation Station based on modifications dating back to 1986 and also alleged NSR violations at the Keystone and Shawville Stations based on modifications dating back to 1984. Met-Ed, JCP&L as the former owner of 16.67% of the Keystone Station, and Penelec, as former owner and operator of the Shawville Station, are unable to predict the outcome of this matter.

In June 2008, the EPA issued a Notice and Finding of Violation to Mission Energy Westside, Inc. alleging that modifications at the Homer City Power Station occurred since 1988 to the present without preconstruction NSR permitting under the CAA s PSD program. In May 2010, the EPA issued a second NOV to Mission Energy Westside, Inc., Penelec, NYSEG and others that have had an ownership interest in the Homer City Power Station containing in all material respects identical allegations as the June 2008 NOV. On July 20, 2010, the states of New York and Pennsylvania provided Mission Energy Westside, Inc., Penelec, NYSEG and others that have had an ownership interest in the Homer City Power Station a notification required 60 days prior to filing a citizen suit under the CAA. Mission Energy is seeking indemnification from Penelec, the co-owner and operator of the Homer City Power Station prior to its sale in 1999. The scope of Penelec s indemnity obligation to and from Mission Energy is under dispute and Penelec is unable to predict the outcome of this matter.

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 generating 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 scheduled maintenance at the Eastlake generating plant may constitute a major modification under the NSR provision of the CAA. Later in 2009, FGCO received another information request regarding emission projections for the Eastlake generating plant. 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.

National Ambient Air Quality Standards

The EPA s CAIR requires reductions of NO_X 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 NO_X emissions to 1.3 million tons annually. In 2008, the U.S. Court of Appeals for the District of Columbia 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 NO_X 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 2010, the EPA proposed the Clean Air Transport Rule (CATR) to replace CAIR, which remains in effect until the EPA finalizes CATR. CATR requires reductions of NO_X and SO_2 emissions in two phases (2012 and 2014), ultimately capping SO_2 emissions in affected states to 2.6 million tons annually and NO_X emissions to 1.3 million tons annually. The EPA proposed a preferred regulatory approach that allows trading of NO_X and SO_2 emission allowances between power plants located in the same state with severe limits on interstate trading and two alternative approaches the first eliminates interstate trading of NO_X and SO_2 emission allowances and the second eliminates trading of NO_X and SO_2 emission allowances in its entirety. Depending on the actions taken by the EPA with respect to CATR, the proposed MACT regulations discussed below, and any future regulations that are ultimately implemented, FGCO s future cost of compliance may be substantial. Management is currently assessing the impact of these environmental proposals and other factors on FCGO s facilities, particularly on the operation of its smaller, non-supercritical units. For example, management may decide to idle certain of these units or operate them on a seasonal basis until developments clarify.

Hazardous Air Pollutant Emissions

The EPA s CAMR provides for a cap-and-trade program to reduce mercury emissions from coal-fired power plants in two phases; initially, capping nationwide emissions of mercury at 38 tons by 2010 (as a co-benefit from implementation of SO_2 and NO_X emission caps under the EPA s CAIR program) and 15 tons per year by 2018. The U.S. Court of Appeals for the District of Columbia, at the urging of several states and environmental groups vacated the CAMR, ruling that the EPA failed to take the necessary steps to de-list coal-fired power plants from its hazardous air pollutant program and, therefore, could not promulgate a cap-and-trade program. The EPA entered into a consent decree requiring it to propose maximum achievable control technology (MACT) regulations for mercury and other hazardous air pollutants by March 16, 2011, and to finalize the regulations by November 16, 2011. On April 29, 2010, the EPA issued proposed MACT regulations requiring emissions reductions of mercury and other hazardous air pollutants from non-electric generating unit boilers, including boilers which do not use fossil fuels such as the proposed Burger biomass repowering project. If finalized, the non-electric generating unit MACT regulations could also provide precedent for MACT standards applicable to electric generating units. Depending on the action taken by the EPA and on how any future regulations are ultimately implemented, FGCO s future cost of compliance with MACT regulations may be substantial and changes to FGCO s operations may result.

Pennsylvania has submitted a new mercury rule for EPA approval that does not provide a cap-and-trade approach as in the CAMR, but rather follows a command-and-control approach imposing emission limits on individual sources. On December 23, 2009, the Supreme Court of Pennsylvania affirmed the Commonwealth Court of Pennsylvania ruling that Pennsylvania s mercury rule is unlawful, invalid and unenforceable and enjoined the Commonwealth from continued implementation or enforcement of that rule.

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, on June 26, 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, ensuring that 10% of electricity used in the United States comes from renewable sources by 2012, increasing to 25% by 2025, and implementing an economy-wide cap-and-trade program to reduce GHG emissions by 80% by 2050. State activities, primarily the northeastern states participating in the Regional Greenhouse Gas Initiative and western states, led by California, have coordinated efforts to develop regional strategies to control emissions of certain GHGs.

The EPA has authority under the CAA to regulate air pollutants from electric generating plants and other facilities. In September 2009, the EPA finalized a national GHG emissions collection and reporting rule that will require FirstEnergy to measure GHG emissions commencing in 2010 and submit reports commencing in 2011. 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 GHG increase the threat of climate change. 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 will 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 program would be required. The EPA established an emissions applicability threshold of 75,000 tons per year (tpy) of carbon dioxide equivalents (CO_2e) effective January 2, 2011 for existing facilities under the CAA s Prevention of Significant Determination (PSD) program, but until July 1, 2011 that emissions applicability threshold will only apply if PSD is triggered by non-carbon dioxide pollutants.

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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 which recognized the scientific view that the increase in global temperature should be below two degrees Celsius, included 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 established the Copenhagen Green Climate Fund to support mitigation, adaptation, and other climate-related activities in developing countries. Once 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.

On September 21, 2009, the U.S. Court of Appeals for the Second Circuit and on October 16, 2009, 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. While FirstEnergy is not a party to this litigation, should the court of appeals decision be affirmed or not subjected to further review, FirstEnergy and/or one or more of its subsidiaries could be named in actions making similar allegations.

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 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, Ohio, New Jersey and Pennsylvania have water quality standards applicable to FirstEnergy s operations.

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). 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. On April 1, 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. The EPA is developing a new regulation under Section 316(b) of the Clean Water Act consistent with the opinions of the Supreme Court and the Court of Appeals which have created significant uncertainty about the specific nature, scope and timing of the final performance standard. 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. On March 15, 2010, the EPA issued a draft permit for the Bay Shore power 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 June 2008, the U.S. Attorney s Office in Cleveland, Ohio advised FGCO that it is 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. FGCO is unable to predict the outcome of this matter.

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.

On December 30, 2009, in an advanced notice of public rulemaking, the EPA said that the large volumes of coal combustion residuals produced by electric utilities pose significant financial risk to the industry. On May 4, 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. FGCO s future cost of compliance with any coal combustion residuals regulations which 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.

The Utilities 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 June 30, 2010, based on estimates of the total costs of cleanup, the Utilities proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $105 million (JCP&L $76 million, TE $1 million, CEI $1 million, FGCO $1 million and FirstEnergy $26 million) have been accrued through June 30, 2010. Included in the total are accrued liabilities of approximately $67 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.

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 s territory. 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. Early in 2010, the Appellate Division heard oral argument on plaintiff s appeal of the trial court s decision decertifying the class, and on July 29, 2010, the Appellate Division upheld the trial court s decision.

Litigation Relating to the Proposed Allegheny Energy Merger

In connection with the proposed merger (Note 15), purported shareholders of Allegheny Energy have filed putative shareholder class action and/or derivative lawsuits in Pennsylvania and Maryland state courts, as well as in the U.S. District Court for the Western District of Pennsylvania, against Allegheny Energy and its directors and certain officers, referred to as the Allegheny Energy defendants, FirstEnergy and Merger Sub. In summary, the lawsuits allege, among other things, that the Allegheny Energy directors breached their fiduciary duties by approving the merger agreement, and that Allegheny Energy, FirstEnergy and Merger Sub aided and abetted in these alleged breaches of fiduciary duty. The complaints seek, among other things, jury trials, money damages and injunctive relief. Additional details about the actions are provided below. While FirstEnergy believes the lawsuits are without merit and has defended vigorously against the claims, in order to avoid the costs associated with the litigation, the defendants have agreed to the terms of a disclosure-based settlement of the lawsuits. The defendants reached an agreement with counsel for all of the plaintiffs concerning fee applications, but a formal stipulation of settlement has not yet been filed with any court. If the parties are unable to obtain final approval of the settlement, then litigation will proceed, and the outcome of any such litigation is inherently uncertain. If a dismissal is not granted or a settlement is not reached, these lawsuits could prevent or delay the completion of the merger and result in substantial costs to FirstEnergy. The defense or settlement of any lawsuit or claim that remains unresolved at the time the merger closes may adversely affect FirstEnergy s business, financial condition or results of operations.

Four putative class action and derivative lawsuits were filed in the Circuit Court for Baltimore City, Maryland. One was withdrawn. The court consolidated the three cases under the caption *Oakmont Capital Management, LLC v. Evanson, et al.*, C.A. No. 24-C-10-1301, and appointed Lewis M. Lynn as Lead Plaintiff. Plaintiff Lynn filed a Consolidated Amended Complaint on April 12, 2010. On April 21, 2010, defendants filed Motions to Dismiss the

Consolidated Amended Complaint for failure to state a claim. The court has stayed all discovery pending resolution of those motions. The court also has entered a stipulated order certifying a class with no opt-out rights. On May 27, 2010, the parties reported to the court that they have agreed to the terms of a disclosure-based settlement and requested that the court cancel the oral argument on the motions to dismiss that had been scheduled for June 3, 2010. On May 28, 2010, the court removed the hearing from its calendar.

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Three shareholder lawsuits were filed in the Court of Common Pleas of Westmoreland County, Pennsylvania, raising putative class action and derivative claims against the Allegheny Energy directors and officers, FirstEnergy and Allegheny Energy. The court has consolidated these actions under the caption, *In re Allegheny Energy, Inc. Shareholder Class and Derivative, Litigation*, Lead Case No. 1101 of 2010, and appointed lead counsel. On April 5, 2010, the Allegheny Energy defendants filed a Motion to Stay the Proceedings. Shortly thereafter, FirstEnergy similarly filed a Motion to Stay. Plaintiffs filed a Motion for Expedited Discovery. The court scheduled a hearing on the motions for May 27, 2010. On May 21, 2010, plaintiffs filed a Verified Consolidated Shareholder Derivative and Class Complaint. On May 26, 2010, the parties filed a Motion for a Continuance of the May 27 hearing, which the court granted. On June 1, 2010, the parties reported to the court that they have agreed to the terms of a disclosure-based settlement.

A putative shareholder lawsuit styled as a class action was filed in the U.S. District Court for the Western District of Pennsylvania and is captioned *Louisiana Municipal Police Employees Retirement System v. Evanson, et al.*, C.A. No. 10-319 NBF. On June 1, 2010, the parties reported to the court that they have agreed to the terms of a disclosure-based settlement.

Nuclear Plant Matters

During a planned refueling outage that began on February 28, 2010, FENOC conducted a non destructive examination and testing of the Control Rod Drive Mechanism (CRDM) Nozzles of the Davis-Besse reactor pressure vessel head. FENOC identified flaws in CRDM nozzles that required modification. The NRC was notified of these findings, along with federal, state and local officials. On March 17, 2010, the NRC sent a special inspection team to Davis-Besse to assess the adequacy of FENOC s identification, analyses and resolution of the CRDM nozzle flaws and to ensure acceptable modifications were made prior to placing the RPV head back in service. After successfully completing the modifications, FENOC committed to take a number of corrective actions including strengthening leakage monitoring procedures and shutting Davis-Besse down no later than October 1, 2011, to replace the reactor pressure vessel head with nozzles made of material less susceptible to primary water stress corrosion cracking further enhancing the safe and reliable operations of the plant. On June 29, 2010, FENOC returned Davis-Besse to service.

On April 5, 2010, the Union of Concerned Scientists (UCS) requested that the NRC issue a Show Cause Order, or otherwise delay the restart of the Davis-Besse Nuclear Power Station until the NRC determines that adequate protection standards have been met and reasonable assurance exists that these standards will continue to be met after the plant s operation is resumed. By a letter dated July 13, 2010, the NRC denied UCS s request for immediate action because the NRC has conducted rigorous and independent assessments of returning the Davis-Besse reactor vessel head to service and its continued operation, and determined that it was safe for the plant to restart. The UCS petition was referred to a petition manager for further review. What additional actions, if any that the NRC takes in response to the UCS request, have not been determined.

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of obligations. As of June 30, 2010, FirstEnergy had approximately $1.9 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. As part of the application to the NRC to transfer the ownership of Davis-Besse, Beaver Valley and Perry to NGC in 2005, FirstEnergy provided an additional $80 million parental guarantee associated with the funding of decommissioning costs for these units and indicated that it planned to contribute an additional $80 million to these trusts by 2010. By a letter dated March 8, 2010, primarily as a result of the Beaver Valley Power Station operating license renewal, FENOC requested that the NRC reduce FirstEnergy s parental guarantee to $15 million and notified the staff that it no longer planned to make the additional contributions into the trusts. By a letter dated July 14, 2010, the NRC stated that it had no objection to the reduction in the parental guarantee.

Other Legal Matters

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy s normal business operations pending against FirstEnergy and its subsidiaries. The other potentially material items not otherwise discussed above are described below.

On April 14, 2010, JCP&L reached an agreement on a settlement package with its bargaining unit employees regarding a grievance challenging JCP&L s 2002 call-out procedure that required bargaining unit employees to respond to emergency power outages. The agreement included an agreed-upon settlement amount and extension of the collective bargaining agreement. On July 22, 2010, the court signed an order approving and implementing the parties agreement. As of June 30, 2010, JCP&L reduced its reserve to $9 million for the settlement which will be paid to the employees over the next thirty days beginning on July 25, 2010. The collective bargaining agreement extension is also effective as of July 25, 2010.

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On February 16, 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. On March 18, 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 has not yet ruled on that motion to dismiss. The named-defendant companies will continue to defend these claims including challenging any class certification.

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. If it were ultimately determined that FirstEnergy or its subsidiaries have legal liability or are otherwise made subject to liability based on the above matters, 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 10 of the Combined Notes to the Consolidated Financial Statements (Unaudited) for discussion of new accounting pronouncements.

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 subsidiaries, FGCO and NGC, owns or leases and operates and maintains FirstEnergy s fossil and hydroelectric generation 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 government aggregation programs, the sale of electricity to Met-Ed and Penelec to meet all of their POLR and default service requirements and its participation in affiliated and non-affiliated POLR auctions. FES revenues also include sales to non-affiliated customers in Ohio, Pennsylvania, New Jersey, Maryland, Michigan, Illinois and Maryland.

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 above under the following subheadings, which information is incorporated by reference herein: 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 $254 million in the first six months of 2010, compared to the same period of 2009. The decrease was primarily due to higher purchased power costs, the absence of a $252 million ($158 million after tax) gain in 2009 from the sale of a 9% participation interest in OVEC and increased fuel and interest expense, partially offset by higher revenues and investment income.

Revenues

Total revenues, excluding the OVEC sale, increased $388 million in the first six months of 2010, compared to the same period of 2009 primarily due to an increase in direct and government aggregation sales volumes and sales of RECs, partially offset by decreases in POLR sales to the Ohio Companies and wholesale sales.

The increase in revenues resulted from the following sources:

	Six Months Ended June 30		Increase
Revenues by Type of Service	**2010**	**2009**	**(Decrease)**
	(In millions)		
Direct and Government Aggregation	$ 1,097	$ 174	$ 923
POLR	1,260	1,732	(472)
Wholesale	186	311	(125)
Transmission	36	41	(5)
RECs	67		67
Sale of OVEC participation interest		252	(252)
Other	57	57	
Total Revenues	**$ 2,703**	**$ 2,567**	**$ 136**

The increase in direct and government aggregation revenues of $923 million resulted from increased revenue in both the MISO and PJM markets. The increase in revenue primarily resulted from the acquisition of new commercial and industrial customers, as well as new government aggregation contracts with communities in Ohio that provide generation to approximately 1.1 million residential and small commercial customers at the end of June 2010 compared to approximately 21,000 at the end of June 2009, partially offset by lower unit prices. During January 2010, FES began supplying power to approximately 425,000 NOPEC customers.

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The decrease in POLR revenues of $472 million was due to lower sales volumes to the Ohio Companies and lower unit prices, partially offset by increased sales volumes and higher unit prices to the Pennsylvania Companies. The lower sales volumes and unit prices to the Ohio Companies in 2010 reflected the results of the May 2009 power procurement process. The increased revenues to the Pennsylvania Companies resulted from FES supplying Met-Ed and Penelec with volumes previously supplied through a third-party contract at prices that were slightly higher than in 2009.

Wholesale revenues decreased $125 million due to reduced volumes reflecting market declines and lower prices.

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

Source of Change in Direct and Government Aggregation	**Increase (Decrease)** *(In millions)*
Direct Sales:	
Effect of increase in sales volumes	$ 633
Change in prices	(47)
	586
Government Aggregation	
Effect of an increase in sales volumes	337
Change in prices	
	337
Net Increase in Direct and Gov t Aggregation Revenues	$ 923

Source of Change in Wholesale Revenues	**(Decrease)** *(In millions)*
POLR:	
Effect of 15.1% decrease in sales volumes	$ (262)
Change in prices	(210)
	(472)
Wholesale:	
Effect of 56.7% decrease in sales volumes	(123)
Change in prices	(2)
	(125)
Decrease in Wholesale Revenues	$ (597)

Transmission revenues decreased $5 million due primarily to lower PJM congestion revenue.

Expenses

Total expenses increased $539 million in the first six months of 2010, compared with the same period of 2009.

The following table summarizes the factors contributing to the changes in fuel and purchased power costs in the first six months of 2010, from the same period last year:

Source of Change in Fuel and Purchased Power	**Increase (Decrease)** ***(In millions)***
Fossil Fuel:	
Change due to increased unit costs	$ 33
Change due to volume consumed	40
	73
Nuclear Fuel:	
Change due to increased unit costs	18
Change due to volume consumed	3
	21
Non-affiliated Purchased Power:	
Power contract mark-to-market adjustment	17
Change due to decreased unit costs	(98)
Change due to volume purchased	484
	403
Affiliated Purchased Power:	
Change due to decreased unit costs	(4)
Change due to volume purchased	19
	15
Net Increase in Fuel and Purchased Power Costs	**$ 512**

Fossil fuel costs increased $73 million in the first six months of 2010, compared to the same period of 2009, as a result of higher volumes consumed combined with increased prices. Increased volume reflects higher generation in the first six months of 2010, compared to the same period last year due to improving economic conditions. The increased costs reflect higher coal and transportation charges in the first six months of 2010, compared to the same period last year. Nuclear fuel costs increased $21 million, primarily due to the replacement of nuclear fuel at higher unit costs following the refueling outages that occurred in 2009.

Non-affiliated purchased power costs increased $403 million due primarily to higher volumes purchased and a power contract mark-to-market adjustment, partially offset by lower unit costs. The increase in volume primarily relates to the assumption of a 1,300 MW contract from Met-Ed and Penelec. Affiliated purchased power increased primarily due to higher volumes purchased from affiliated companies due to the Perry nuclear refueling outage in 2009.

Other operating expenses increased $23 million in the first six months of 2010, compared to the same period of 2009, primarily due to increased transmission expenses ($33 million) and increased uncollectible customer accounts and agent fees associated with the growth in direct and government aggregation sales ($19 million), partially offset by lower nuclear operating costs ($37 million).

General taxes increased $4 million due to sales taxes associated with increased revenues.

Other Expense

Total other expense decreased $2 million in the first six months of 2010, compared to the same period of 2009, primarily due to a $36 million increase in investment income resulting from more favorable performance of nuclear decommissioning trust investments, partially offset by a $31 million increase in interest expense (net of capitalized interest). Interest expense increased primarily due to new long-term debt issued in the second half of 2009 combined with the restructuring of existing long-term debt.

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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. They procure 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 above under the following subheadings, which information is incorporated by reference herein: 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 $28 million in the first six months of 2010, compared to the same period of 2009. The increase primarily resulted from lower purchased power costs and other operating costs, partially offset by lower revenues.

Revenues

Revenues decreased $473 million, or 33.3%, in the first six months of 2010, compared with the same period in 2009, due primarily to a decrease in generation revenues. Distribution revenues also were lower than they were in the first half of 2009.

Retail generation revenues decreased $438 million primarily due to a decrease in KWH sales in all customer classes, partially offset by higher average prices in the commercial and industrial classes. Lower KWH sales were primarily the result of a 46.1% increase in customer shopping in the first six months of 2010. Lower KWH sales to residential customers were partially offset by increased weather-related usage in the first six months of 2010, reflecting a 62% increase in cooling degree days in OE s service territory. Higher average prices in the commercial and industrial classes resulted from the CBP auction for the service period beginning June 1, 2009.

Changes in retail generation KWH sales and revenues in the first six months of 2010, compared to the same period in 2009, are summarized in the following tables:

Retail Generation KWH Sales	**Decrease**
Residential	(30.3)%
Commercial	(60.0)%
Industrial	(64.3)%
Decrease in Retail Generation Sales	**(48.1)%**

Retail Generation Revenues	**Decrease** *(In millions)*
Residential	$ (143)
Commercial	(167)
Industrial	(128)
Decrease in Retail Generation Revenues	**$ (438)**

Distribution revenues decreased $17 million in the first six months of 2010, compared to the same period in 2009, due to lower commercial and industrial revenues, partially offset by higher residential revenues. Commercial and industrial revenues were primarily impacted by lower average unit prices, resulting from lower transmission rates in 2010. Residential distribution revenues were higher due to higher average unit prices resulting from the 2009 ESP and slightly higher KWH deliveries resulting from the warmer conditions described above. Increased industrial deliveries were the result of improving economic conditions, reflecting an increase in KWH deliveries to major steel customers (36%) and automotive customers (27%).

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Changes in distribution KWH deliveries and revenues in the first six months of 2010, compared to the same period in 2009, are summarized in the following tables:

Distribution KWH Sales	Increase
Residential	0.2%
Commercial	0.7%
Industrial	12.7%
Increase in Distribution Deliveries	**4.0%**

Distribution Revenues	Increase (Decrease) *(In millions)*
Residential	$ 9
Commercial	(8)
Industrial	(18)
Net Decrease in Distribution Revenues	**$ (17)**

Wholesale revenues decreased $11 million primarily due to lower unit prices, partially offset by an increase in sales to FES from OE s leasehold interests in Perry Unit 1 and Beaver Valley Unit 2.

Expenses

Total expenses decreased $521 million in the first six months of 2010, from the same period of 2009. The following table presents changes from the prior period by expense category:

Expenses Changes	(Decrease) *(In millions)*
Purchased power costs	$ (422)
Other operating expenses	(93)
Amortization of regulatory assets, net	(4)
General taxes	(2)
Decrease in Expenses	**$ (521)**

Purchased power costs decreased in the first six months of 2010, compared to the same period of 2009, primarily due to lower KWH purchases resulting from increased customer shopping in the first six months of 2010 and slightly lower unit costs. The decrease in other operating costs for the first six months of 2010, was primarily due to lower MISO transmission expenses (assumed by third party suppliers beginning June 1, 2009) and the absence in 2010 of $18 million of costs incurred in the first six months of 2009 associated with regulatory obligations for economic development and energy efficiency programs under OE s 2009 ESP. Lower amortization of net regulatory assets was primarily due to lower amortization of deferred MISO transmission costs, partially offset by the recovery of certain regulatory assets that began in 2010. The decrease in general taxes was primarily due to lower Ohio KWH taxes and lower property taxes.

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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: 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 increased by $94 million in the first six months of 2010, compared to the same period of 2009. The increase in earnings was primarily due to the absence in 2010 of one-time regulatory charges recognized in 2009, and decreased purchased power and other operating costs, partially offset by decreased revenues and deferred regulatory assets.

Revenues

Revenues decreased $299 million, or 32%, in the first six months of 2010, compared to the same period of 2009, due to decreased retail generation and distribution revenues.

Retail generation revenues decreased $200 million in the first six months of 2010, compared to the same period of 2009, primarily due to lower KWH sales across all customer classes, partially offset by higher average unit prices in all customer classes. Reduced KWH sales were primarily the result of increased customer shopping in the first six months of 2010. Lower KWH sales to residential customers were partially offset by increased weather-related usage in the first six months of 2010, reflecting a 113% increase in cooling degree days. Retail generation prices increased in 2010 as a result of the CBP auction for the service period beginning June 1, 2009.

Changes in retail generation sales and revenues in the first six months of 2010, compared to the same period of 2009, are summarized in the following tables:

Retail Generation KWH Sales	**Decrease**
Residential	(54.3)%
Commercial	(68.5)%
Industrial	(49.2)%
Decrease in Retail Generation Sales	**(55.6)%**

Retail Generation Revenues	**Decrease**
	(In millions)
Residential	$ (50)
Commercial	(80)
Industrial	(70)
Decrease in Retail Generation Revenues	**$ (200)**

Distribution revenues decreased $91 million in the first six months of 2010, compared to the same period of 2009, due to lower average unit prices for all customer classes and decreased KWH deliveries in the residential sector, partially offset by increased KWH deliveries in the industrial and commercial sectors. The lower average unit prices were the result of lower transition rates in 2010. Increased industrial deliveries were the result of improving economic conditions, reflecting an increase in KWH deliveries to major steel customers (158%) and automotive customers (14%).

Changes in distribution KWH deliveries and revenues in the first six months of 2010, compared to the same period of 2009, are summarized in the following tables:

Distribution KWH Sales	Increase (Decrease)
Residential	(0.6)%
Commercial	1.7%
Industrial	12.0%
Net Increase in Distribution Deliveries	**5.1%**

Distribution Revenues	Decrease (In millions)
Residential	$ (13)
Commercial	(28)
Industrial	(50)
Decrease in Distribution Revenues	**$ (91)**

Expenses

Total expenses decreased $452 million in the first six months of 2010, compared to the same period of 2009. The following table presents the change from the prior period by expense category:

Expenses Changes	Increase (Decrease) (In millions)
Purchased power costs	$ (325)
Other operating costs	(44)
Amortization of regulatory assets, net	(210)
Deferral of new regulatory assets	135
General taxes	(8)
Net Decrease in Expenses	**$ (452)**

Purchased power costs decreased in the first six months of 2010, primarily due to lower KWH sales requirements as discussed above. Other operating costs decreased due to lower transmission expenses (assumed by third party suppliers beginning June 1, 2009), labor and employee benefit expenses and the absence in 2010 of $12 million of costs incurred in the first six months of 2009 associated with regulatory obligations for economic development and energy efficiency programs. Decreased amortization of regulatory assets was due primarily to the 2009 impairment of CEI s Extended RTC regulatory asset of $216 million in accordance with the PUCO-approved ESP. A decrease in the deferral of new regulatory assets was primarily due to CEI s contemporaneous recovery of purchased power costs in 2010. General taxes decreased in the first six months of 2010, primarily due to a 2010 favorable tax settlement in Ohio.

Other Expense

Other expense increased $4 million in the first six months of 2010, compared to the same period of 2009 due to lower investment income and higher interest expense associated with the August 2009 issuance of $300 million first mortgage bonds, partially offset by the November 2009 redemption of $150 million senior secured notes.

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: 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 $7 million in the first six months of 2010, compared to the same period of 2009. The increase was primarily due to decreased net amortization of regulatory assets, purchased power and other operating costs, partially offset by an increase in interest expense and decreases in revenues and investment income.

Revenues

Revenues decreased $218 million, or 46%, in the first six months of 2010, compared to the same period of 2009, primarily due to lower retail generation and distribution revenues, partially offset by an increase in wholesale generation revenues.

Retail generation revenues decreased $203 million in the first six months of 2010, compared to the same period of 2009, primarily due to lower KWH sales across all customer classes and lower unit prices to industrial customers. Lower KWH sales to all customer classes were primarily the result of a 63% increase in customer shopping in the first six months of 2010. Lower unit prices for industrial customers are primarily due to the absence of TE s fuel cost recovery and rate stabilization riders that were effective from January through May 2009, partially offset by increased generation prices resulting from the CBP auction, effective June 1, 2009.

Changes in retail generation KWH sales and revenues in the first six months of 2010, compared to the same period of 2009, are summarized in the following tables:

Retail Generation KWH Sales	**Decrease**
Residential	(48.6)%
Commercial	(72.3)%
Industrial	(60.8)%
Decrease in Retail Generation Sales	**(60.5)%**

Retail Generation Revenues	**Decrease**
	(In millions)
Residential	$ (44)
Commercial	(72)
Industrial	(87)
Decrease in Retail Generation Revenues	**$ (203)**

Distribution revenues decreased $26 million in the first six months of 2010, compared to the same period of 2009, primarily due to lower unit prices in all customer classes, partially offset by increased KWH deliveries to industrial customers. Lower unit prices are primarily due to lower transmission rates. Increased industrial deliveries were the result of improving economic conditions, reflecting an increase in KWH deliveries to major automotive customers

(36%) and steel customers (37%).

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Changes in distribution KWH deliveries and revenues in the first six months of 2010, compared to the same period of 2009, are summarized in the following tables:

Distribution KWH Deliveries	Increase (Decrease)
Residential	(0.4)%
Commercial	(1.6)%
Industrial	14.8%
Net Increase in Distribution Deliveries	**6.2%**

Distribution Revenues		Decrease
		(In millions)
Residential	$	(5)
Commercial		(6)
Industrial		(15)
Decrease in Distribution Revenues	**$**	**(26)**

Wholesale revenues increased $7 million in the first six months of 2010, compared to the same period of 2009, primarily due to higher revenues from sales to NGC from TE s leasehold interest in Beaver Valley Unit 2.

Expenses

Total expenses decreased $241 million in the first six months of 2010, compared to the same period of 2009. The following table presents changes from the prior period by expense category:

Expenses Changes		Decrease
		(In millions)
Purchased power costs	$	(179)
Other operating costs		(29)
Amortization of regulatory assets, net		(32)
General taxes		(1)
Decrease in Expenses	**$**	**(241)**

Purchased power costs decreased $179 million in the first six months of 2010, compared to the same period of 2009 due to lower volume as a result of decreased KWH sales requirements. Other operating costs decreased $29 million primarily due to reduced transmission expense (assumed by third party suppliers beginning June 1, 2009), lower costs associated with regulatory obligations for economic development and energy efficiency programs and decreased labor expenses. The $32 million decrease in net regulatory asset amortization was primarily due to PUCO-approved cost deferrals and lower MISO transmission cost amortization, partially offset by the absence of MISO transmission and fuel cost deferrals in the first six months of 2010, compared to the same period of 2009.

Other Expense

Other expense increased $13 million in the first six months of 2010, compared to the same period of 2009, primarily due to higher interest expense associated with the April 2009 issuance of $300 million senior secured notes and lower investment income.

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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: 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 $13 million in the first six months of 2010, compared to the same period of 2009. The increase was primarily due to lower purchased power costs and decreased amortization of regulatory assets, partially offset by lower revenues and increased other operating costs.

Revenues

In the first six months of 2010, revenues decreased $57 million, or 4%, compared to the same period of 2009. The decrease in revenues is primarily due to a decrease in retail and wholesale generation revenues, partially offset by higher distribution and transmission revenues.

Retail generation revenues decreased $73 million due to lower retail generation KWH sales in commercial and industrial classes, partially offset by higher KWH sales in the residential class. Lower sales to the commercial and industrial classes were primarily due to an increase in the number of shopping customers. Higher KWH sales to the residential class reflected increased weather-related usage resulting from a 105% increase in cooling degree days.

Changes in retail generation KWH sales and revenues in the first six months of 2010, compared to the same period of 2009, are summarized in the following tables:

Retail Generation KWH Sales	**Increase (Decrease)**
Residential	5.1%
Commercial	(31.0)%
Industrial	(24.7)%
Net Decrease in Retail Generation Sales	**(10.1)%**

Retail Generation Revenues	**Increase (Decrease)**
	(In millions)
Residential	$ 30
Commercial	(95)
Industrial	(8)
Net Decrease in Retail Generation Revenues	**$ (73)**

Wholesale generation revenues decreased $7 million in the first six months of 2010, compared to the same period of 2009; less power was available for sale due to the termination of a NUG power purchase contract in July 2009.

Distribution revenues increased $17 million in the first six months of 2010, compared to the same period of 2009, due to higher KWH deliveries in all customer classes. Increased usage from warmer weather and improving economic conditions in JCP&L s service territory was partially offset by a decrease in composite unit prices in the commercial and industrial classes.

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Changes in distribution KWH deliveries and revenues in the first six months of 2010 compared to the same period of 2009, are summarized in the following tables:

Distribution KWH Sales	Increase
Residential	5.1%
Commercial	1.7%
Industrial	1.1%
Increase in Distribution Deliveries	**3.1%**

Distribution Revenues	Increase (Decrease) *(In millions)*
Residential	$ 18
Commercial	
Industrial	(1)
Net Increase in Distribution Revenues	**$ 17**

Transmission revenues increased $4 million in the first six months of 2010, compared to the same period of 2009, due to an increase in network transmission system revenues from PJM.

Expenses

Total expenses decreased $77 million in the first six months of 2010, compared to the same period of 2009. The following table presents changes from the prior period by expense category:

Expenses Changes	Increase (Decrease) *(In millions)*
Purchased power costs	$ (81)
Other operating costs	14
Provision for depreciation	5
Amortization of regulatory assets, net	(16)
General taxes	1
Net Decrease in Expenses	**$ (77)**

Purchased power costs decreased in the first six months of 2010 primarily due to the lower KWH sales requirements and the termination of a NUG contract in July 2009. Other operating costs increased in the first six months of 2010 primarily due to higher tree trimming costs resulting from major storm clean up in JCP&L s service territory, offset by a favorable labor settlement of $7 million in the second quarter of 2010. Depreciation expense increased due to an increase in depreciable property since the second quarter of 2009. Net regulatory asset amortization decreased in the first six months of 2010 primarily due to deferral of the storm costs.

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 electing to retain Met-Ed as their power supplier. Met-Ed has a partial requirements wholesale power sales agreement with FES, to supply nearly all of its energy requirements at fixed prices through 2010.

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: 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 $3 million in the first six months of 2010, compared to the same period of 2009. The increase was primarily due to increased revenues, partially offset by increased purchased power, other operating expenses and amortization of net regulatory assets.

Revenues

The revenue increase of $109 million, or 13%, in the first six months of 2010 compared to the same period of 2009 reflected higher distribution, wholesale and generation revenues, partially offset by a decrease in transmission revenues.

Distribution revenues increased $57 million in the first six months of 2010, compared to the same period of 2009, primarily due to higher transmission rates, resulting from the annual update to Met-Ed s TSC rider effective June 1, 2009 and 2010, partially offset by lower CTC rates for the residential class. Higher KWH deliveries to commercial and industrial customers were due to improving economic conditions in Met-Ed s service territory. Higher residential KWH deliveries reflect increased weather-related usage due to a 97% increase in cooling degree days in the first six months of 2010, partially offset by a 10% decrease in heating degree days for the same time period.

Changes in distribution KWH deliveries and revenues in the first six months of 2010, compared to the same period of 2009 are summarized in the following tables:

Distribution KWH Deliveries	Increase
Residential	0.7%
Commercial	4.2%
Industrial	4.5%
Increase in Distribution Deliveries	**2.8%**

Distribution Revenues	Increase
	(In millions)
Residential	$ 23
Commercial	21
Industrial	13
Increase in Distribution Revenues	**$ 57**

Wholesale revenues increased $40 million in the first six months of 2010 compared to the same period of 2009, primarily reflecting higher PJM capacity prices.

Retail generation revenues increased $21 million in the first six months of 2010, compared to the same period of 2009, due to higher composite unit prices in the residential and commercial customer classes and higher KWH sales to all customer classes.

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Changes in retail generation KWH sales and revenues in the first six months of 2010, compared to the same period of 2009, are summarized in the following tables:

Retail Generation KWH Sales	Increase
Residential	0.7%
Commercial	3.7%
Industrial	3.5%
Increase in Retail Generation Sales	**2.4%**

Retail Generation Revenues	Increase *(In millions)*
Residential	$ 14
Commercial	5
Industrial	2
Increase in Retail Generation Revenues	**$ 21**

Transmission revenues decreased $9 million in the first six months of 2010 compared to the same period of 2009 primarily due to decreased Financial Transmission Rights revenues. Met-Ed defers the difference between transmission revenues and transmission costs incurred, resulting in no material effect to current period earnings.

Expenses

Total expenses increased $103 million in the first six months of 2010 compared to the same period of 2009. The following table presents changes from the prior year by expense category:

Expenses Changes	Increase (Decrease) *(In millions)*
Purchased power costs	$ 61
Other operating costs	35
Provision for depreciation	1
Amortization of regulatory assets, net	8
General taxes	(2)
Net Increase in Expenses	**$ 103**

Purchased power costs increased $61 million in the first six months of 2010 due to an increase in unit costs and increased KWH purchased to source increased generation sales requirements. Other operating costs increased $35 million in the first six months of 2010 compared to the same period in 2009 primarily due to higher transmission congestion expenses. The amortization of regulatory assets increased $8 million in the first six months of 2010 primarily due to increased transmission cost recovery. General taxes decreased $2 million mostly due to a Pennsylvania tax amnesty settlement. Depreciation expense increased $1 million due to an increase in depreciable property since June of 2009.

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 transmission and distribution services. Penelec also procures generation services for those customers electing to retain Penelec as their power supplier. Penelec has a partial requirements wholesale power sales agreement with FES, to supply nearly all of its energy requirements at fixed prices through 2010.

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: 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 $3 million in the first six months of 2010, compared to the same period of 2009. The decrease was primarily due to higher purchased power and other operating costs, partially offset by higher revenues and lower amortization (deferral) of net regulatory assets and general taxes.

Revenues

In the first six months of 2010, revenues increased $50 million, or 6.9%, compared to the same period of 2009. The increase in revenue was primarily due to higher retail and wholesale generation revenues, partially offset by lower distribution and transmission revenues.

Retail generation revenues increased $39 million in the first six months of 2010, compared to the same period of 2009, primarily due to higher unit prices and KWH sales in all customer classes. Higher unit prices across all customer classes are primarily due to an increase in the generation rate, effective January 1, 2010. Higher KWH sales to commercial and industrial customers were due to improving economic conditions in Penelec s service territory. Higher KWH sales to residential customers increased primarily due to weather-related usage, reflecting a 129% increase in cooling degree days in the first six months of 2010, partially offset by a 10% decrease in heating degree days for the same time period.

Changes in retail generation sales and revenues in the first six months of 2010 compared to the same period of 2009 are summarized in the following tables:

Retail Generation KWH Sales	**Increase**
Residential	1.3%
Commercial	3.9%
Industrial	5.6%
Increase in Retail Generation Sales	**3.4%**

Retail Generation Revenues	**Increase**
	(In millions)
Residential	$ 8
Commercial	17
Industrial	14
Increase in Retail Generation Revenues	**$ 39**

Wholesale generation revenues increased $34 million in the first six months of 2010, compared to the same period of 2009, due primarily to higher PJM capacity prices.

Distribution revenues decreased by $11 million in the first six months of 2010, compared to the same period of 2009, primarily due to a decrease in the CTC rate in all customer classes, partially offset by an increase in the universal service and energy efficiency rates for the residential customer class and increased KWH sales in all customer classes.

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Changes in distribution KWH deliveries and revenues in the first six months of 2010, compared to the same period of 2009, are summarized in the following tables:

Distribution KWH Deliveries	Increase
Residential	1.3%
Commercial	4.0%
Industrial	5.3%
Increase in Distribution Deliveries	**3.5%**

Distribution Revenues	Increase (Decrease) *(In millions)*
Residential	$ 6
Commercial	(10)
Industrial	(7)
Net decrease in Distribution Revenues	**$ (11)**

Transmission revenues decreased by $8 million in the first six months of 2010, compared to the same period of 2009, primarily due to lower Financial Transmission Rights revenue. Penelec defers the difference between transmission revenues and transmission costs incurred, resulting in no material effect to current period earnings.

Expenses

Total expenses increased by $45 million in the first six months of 2010, as compared with the same period of 2009. The following table presents changes from the prior period by expense category:

Expenses Changes	Increase (Decrease) *(In millions)*
Purchased power costs	$ 79
Other operating costs	16
Provision for depreciation	1
Amortization (deferral) of regulatory assets, net	(47)
General taxes	(4)
Net Increase in Expenses	**$ 45**

Purchased power costs increased $79 million in the first six months of 2010, compared to the same period of 2009, primarily due to higher unit costs. Other operating costs increased $16 million in the first six months of 2010, primarily due to increased locational marginal prices partially offset by lower transmission expenses. The amortization (deferral) of net regulatory assets decreased $47 million in the first six months of 2010, primarily due to increased cost deferrals resulting from higher transmission expenses and decreased amortization of regulatory assets resulting from lower CTC revenues. General taxes decreased $4 million primarily due to a favorable ruling on a property tax appeal in the first quarter of 2010.

Other Expense

In the first six months of 2010, other expense increased $8 million primarily due to an increase in interest expense on long-term debt due to the $500 million debt issuance in September 2009.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

ITEM 4. CONTROLS AND PROCEDURES

(a) EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES FIRSTENERGY

FirstEnergy s management, with the participation of its 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 15(d)-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 have concluded that the registrant s disclosure controls and procedures were effective as of the end of the period covered by this report.

(b) CHANGES IN INTERNAL CONTROLS

During the quarter ended June 30, 2010, there were no changes in FirstEnergy s internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the registrant s internal control over financial reporting.

ITEM 4T. CONTROLS AND PROCEDURES FES, OE, CEI, TE, JCP&L, MET-ED AND PENELEC

(a) EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

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

(b) CHANGES IN INTERNAL CONTROLS

During the quarter ended June 30, 2010, there were no changes in the registrants internal control over financial reporting that has materially affected, or are reasonably likely to materially affect, the registrants internal control over financial reporting.

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PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Information required for Part II, Item 1 is incorporated by reference to the discussions in Notes 8 and 9 of the Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q.

ITEM 1A. RISK FACTORS

FirstEnergy s Annual Report on Form 10-K for the year ended December 31, 2009, includes a detailed discussion of its risk factors. There have been no material changes to these risk factors for the quarter ended June 30, 2010.

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 second quarter of 2010.

	Period			
	April	May	June	Second Quarter
Total Number of Shares Purchased[(a)]	75,577	41,674	549,279	666,530
Average Price Paid per Share	$ 38.14	$ 36.28	$ 34.77	$ 35.24
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 under its 2007 Incentive Compensation Plan, Deferred Compensation Plan for Outside Directors, Executive Deferred Compensation Plan, Savings Plan and Stock Investment Plan. In addition, such amounts reflect shares tendered by employees to pay the exercise price or withholding taxes upon exercise of stock options granted under the 2007 Incentive Compensation Plan and the Executive Deferred Compensation Plan.

ITEM 5. OTHER INFORMATION

None

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ITEM 6. EXHIBITS

Exhibit Number

FirstEnergy

2.1	Amendment No.1 to the Agreement and Plan of Merger, dated as of February 10, 2010, by and among FirstEnergy Corp., Element Merger Sub, Inc. and Allegheny Energy, Inc. (incorporated by reference to FirstEnergy s Form S-4 filed June 4, 2010, Exhibit 2.2, File No. 333-165640)
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 June 30, 2010, 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.
	Schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K. The Registrant will furnish the omitted schedules to the Securities and Exchange Commission upon request by the Commission.

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

OE

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

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

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

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
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
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

* Users of this data are advised pursuant to Rule 401 of Regulation S-T that the financial information contained in the XBRL-Related Documents is unaudited and, as a result, investors should not rely on the XBRL-Related Documents in making investment decisions. Furthermore, users of this 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 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.

SIGNATURES

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

August 3, 2010

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/ Kevin R. Burgess

Kevin R. Burgess

Controller
(Principal Accounting Officer)