

AMERICAN ELECTRIC POWER CO INC
Form 10-Q
July 30, 2010

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended June 30, 2010
OR
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Transition Period from ____ to ____

| Commission File Number | Registrant, State of Incorporation, Address of Principal Executive Offices, and Telephone Number | I.R.S. Employer Identification No. |
|---------------------------|---|---|
| 1-3525 | AMERICAN ELECTRIC POWER COMPANY, INC. (A New York Corporation) | 13-4922640 |
| 1-3457 | APPALACHIAN POWER COMPANY (A Virginia Corporation) | 54-0124790 |
| 1-2680 | COLUMBUS SOUTHERN POWER COMPANY (An Ohio Corporation) | 31-4154203 |
| 1-3570 | INDIANA MICHIGAN POWER COMPANY (An Indiana Corporation) | 35-0410455 |
| 1-6543 | OHIO POWER COMPANY (An Ohio Corporation) | 31-4271000 |
| 0-343 | PUBLIC SERVICE COMPANY OF OKLAHOMA (An Oklahoma Corporation) | 73-0410895 |
| 1-3146 | SOUTHWESTERN ELECTRIC POWER COMPANY (A Delaware Corporation) | 72-0323455 |
| All Registrants | 1 Riverside Plaza, Columbus, Ohio 43215-2373 Telephone (614) 716-1000 | |

Indicate by check mark whether the registrants (1) have 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 registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.

Yes X No

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

Yes X No

Indicate by check mark whether Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company have submitted electronically and posted on the AEP corporate website, if any, every Interactive

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Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes

No

Indicate by check mark whether American Electric Power Company, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of 'large accelerated filer,' 'accelerated filer' and 'smaller reporting company' in Rule 12b-2 of the Exchange Act.

Large accelerated
filer

X

Accelerated filer

Non-accelerated
filer

Smaller reporting
company

Indicate by check mark whether Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company are large accelerated filers, accelerated filers, non-accelerated filers or smaller reporting companies. See the definitions of 'large accelerated filer,' 'accelerated filer' and 'smaller reporting company' in Rule 12b-2 of the Exchange Act.

Large accelerated
filer

Accelerated filer

Non-accelerated
filer

X

Smaller reporting
company

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Exchange Act).

Yes

No

X

Columbus Southern Power Company and Indiana Michigan Power Company meet the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and are therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) to Form 10-Q.

Number of shares
of common stock
outstanding of the
registrants at
July 29, 2010

| | |
|---------------------------------------|--------------------|
| American Electric Power Company, Inc. | 479,437,027 |
| | (\$6.50 par value) |
| Appalachian Power Company | 13,499,500 |
| | (no par value) |
| Columbus Southern Power Company | 16,410,426 |
| | (no par value) |
| Indiana Michigan Power Company | 1,400,000 |
| | (no par value) |
| Ohio Power Company | 27,952,473 |
| | (no par value) |
| Public Service Company of Oklahoma | 9,013,000 |
| | (\$15 par value) |
| Southwestern Electric Power Company | 7,536,640 |
| | (\$18 par value) |

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
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June 30, 2010

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This combined Form 10-Q is separately filed by American Electric Power Company, Inc., Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Each registrant makes no representation as to information relating to the other registrants.

GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

| Term | Meaning |
|--------------------------|--|
| AEGCo | AEP Generating Company, an AEP electric utility subsidiary. |
| AEP or Parent | American Electric Power Company, Inc. |
| AEP Consolidated | AEP and its majority owned consolidated subsidiaries and consolidated affiliates. |
| AEP Credit | AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated electric utility companies. |
| AEP East companies | APCo, CSPCo, I&M, KPCo and OPCo. |
| AEP Power Pool | Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies. |
| AEP System or the System | American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries. |
| AEP West companies | PSO, SWEPCo, TCC and TNC. |
| AEPSC | American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries. |
| AFUDC | Allowance for Funds Used During Construction. |
| AOCI | Accumulated Other Comprehensive Income. |
| APCo | Appalachian Power Company, an AEP electric utility subsidiary. |
| APSC | Arkansas Public Service Commission. |
| ASU | Accounting Standard Update. |
| CAA | Clean Air Act. |
| CLECO | Central Louisiana Electric Company, a nonaffiliated utility company. |
| CO ₂ | Carbon Dioxide and other greenhouse gases. |
| Cook Plant | Donald C. Cook Nuclear Plant, a two-unit, 2,191 MW nuclear plant owned by I&M. |
| CSPCo | Columbus Southern Power Company, an AEP electric utility subsidiary. |
| CTC | Competition Transition Charge. |
| CWIP | Construction Work in Progress. |
| DETM | Duke Energy Trading and Marketing L.L.C., a risk management counterparty. |
| DHLC | Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo. |
| E&R | Environmental compliance and transmission and distribution system reliability. |
| EIS | Energy Insurance Services, Inc., a nonaffiliated captive insurance company. |
| ERCOT | Electric Reliability Council of Texas. |
| ESP | Electric Security Plans, filed with the PUCO, pursuant to the Ohio Amendments. |
| ETT | Electric Transmission Texas, LLC, an equity interest joint venture between AEP Utilities, Inc. and MidAmerican Energy Holdings Company Texas Transco, LLC formed to own and operate electric transmission facilities in ERCOT. |
| FAC | Fuel Adjustment Clause. |

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| | |
|-------------|--|
| FASB | Financial Accounting Standards Board. |
| Federal EPA | United States Environmental Protection Agency. |
| FERC | Federal Energy Regulatory Commission. |
| FGD | Flue Gas Desulfurization or Scrubbers. |
| FTR | Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices. |
| GAAP | Accounting Principles Generally Accepted in the United States of America. |

| Term | Meaning |
|---------------------------|---|
| I&M | Indiana Michigan Power Company, an AEP electric utility subsidiary. |
| IGCC | Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas. |
| Interconnection Agreement | Agreement, dated July 6, 1951, as amended, by and among APCo, CSPCo, I&M, KPCo and OPCo, defining the sharing of costs and benefits associated with their respective generating plants. |
| IRS | Internal Revenue Service. |
| IURC | Indiana Utility Regulatory Commission. |
| KGPCo | Kingsport Power Company, an AEP electric utility subsidiary. |
| KPCo | Kentucky Power Company, an AEP electric utility subsidiary. |
| KPSC | Kentucky Public Service Commission. |
| kV | Kilovolt. |
| KWH | Kilowatthour. |
| LPSC | Louisiana Public Service Commission. |
| MISO | Midwest Independent Transmission System Operator. |
| MLR | Member load ratio, the method used to allocate AEP Power Pool transactions to its members. |
| MMBtu | Million British Thermal Units. |
| MPSC | Michigan Public Service Commission. |
| MTM | Mark-to-Market. |
| MW | Megawatt. |
| MWH | Megawatthour. |
| NEIL | Nuclear Electric Insurance Limited. |
| NOx | Nitrogen oxide. |
| Nonutility Money Pool | AEP's Nonutility Money Pool. |
| NSR | New Source Review. |
| OCC | Corporation Commission of the State of Oklahoma. |
| OPCo | Ohio Power Company, an AEP electric utility subsidiary. |
| OPEB | Other Postretirement Benefit Plans. |
| OTC | Over the counter. |
| OVEC | Ohio Valley Electric Corporation, which is 43.47% owned by AEP. |
| PJM | Pennsylvania – New Jersey – Maryland regional transmission organization. |
| PM | Particulate Matter. |
| PSO | Public Service Company of Oklahoma, an AEP electric utility subsidiary. |
| PUCO | Public Utilities Commission of Ohio. |
| PUCT | Public Utility Commission of Texas. |
| Registrant Subsidiaries | AEP subsidiaries which are SEC registrants; APCo, CSPCo, I&M, OPCo, PSO and SWEPCo. |
| Risk Management Contracts | Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges. |
| Rockport Plant | A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana, owned by AEGCo and I&M. |
| RTO | Regional Transmission Organization. |
| S&P | Standard and Poor's. |
| Sabine | Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity. |

| Term | Meaning |
|---------------------------------|--|
| SIA | System Integration Agreement. |
| SNF | Spent Nuclear Fuel. |
| SO ₂ | Sulfur Dioxide. |
| SPP | Southwest Power Pool. |
| Stall Unit | J. Lamar Stall Unit at Arsenal Hill Plant. |
| SWEPCo | Southwestern Electric Power Company, an AEP electric utility subsidiary. |
| TCC | AEP Texas Central Company, an AEP electric utility subsidiary. |
| Texas Restructuring Legislation | Legislation enacted in 1999 to restructure the electric utility industry in Texas. |
| TNC | AEP Texas North Company, an AEP electric utility subsidiary. |
| True-up Proceeding | A filing made under the Texas Restructuring Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts. |
| Turk Plant | John W. Turk, Jr. Plant. |
| Utility Money Pool | AEP System's Utility Money Pool. |
| VIE | Variable Interest Entity. |
| Virginia SCC | Virginia State Corporation Commission. |
| WPCo | Wheeling Power Company, an AEP electric utility subsidiary. |
| WVPSC | Public Service Commission of West Virginia. |

FORWARD-LOOKING INFORMATION

This report made by AEP and its Registrant Subsidiaries contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- The economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- Electric load, customer growth and the impact of retail competition.
- Weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters.
- Availability of necessary generating capacity and the performance of our generating plants.
- Our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process.
- Our ability to recover regulatory assets and stranded costs in connection with deregulation.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates.
- New legislation, litigation and government regulation, including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance).
- Resolution of litigation (including our dispute with Bank of America).
- Our ability to constrain operation and maintenance costs.
- Our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities.
- Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in the ratings of debt.
- Volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities.
-

Changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP.

- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements.
- Prices and demand for power that we generate and sell at wholesale.
- Changes in technology, particularly with respect to new, developing or alternative sources of generation.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.
- Our ability to recover through rates the remaining unrecovered investment, if any, in generating units that may be retired before the end of their previously projected useful lives.

AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

Economic Conditions

Retail margins increased during the first six months of 2010 due to successful rate proceedings in various jurisdictions and higher residential and commercial demand for electricity as a result of favorable weather throughout AEP's service territory. In comparison to the recessionary lows of 2009, industrial sales increased 9% in the second quarter and 4% during the first six months of 2010.

Due to the continued slow recovery in the U.S. economy and a corresponding negative impact on energy consumption, we implemented cost reduction initiatives in the second quarter of 2010 to reduce our workforce by 11.5% and reduce other operation and maintenance spending. Achieving these goals involved identifying process improvements, streamlining organizational designs and developing other efficiencies that will deliver additional sustainable savings. In the second quarter of 2010, we recorded \$293 million of expense related to these cost reduction initiatives.

Regulatory Activity

Our significant 2010 rate proceedings include:

Kentucky – In June 2010, the KPSC approved a \$64 million annual increase in base rates based on a 10.5% return on common equity. New rates became effective with the first billing cycle of July 2010.

Michigan – In January 2010, I&M filed for a \$63 million increase in annual base rates based on an 11.75% return on common equity. In the August billing cycle, I&M, with MPSC authorization, will implement a \$44 million interim rate increase, subject to refund with interest.

Oklahoma – In July 2010, PSO filed for an \$82 million increase in annual base rates, including \$30 million that is currently being recovered through a rider. The requested increase is based on an 11.5% return on common equity. PSO also requested that new rates become effective no later than July 2011.

Texas – In April 2010, a settlement was approved by the PUCT to increase SWEPCo's base rates by approximately \$15 million annually, effective May 2010, including a return on equity of 10.33%. The settlement agreement also allows SWEPCo a \$10 million one-year surcharge rider to recover additional vegetation management costs that SWEPCo must spend within two years.

Virginia – In July 2010, the Virginia SCC ordered an annual increase in revenues of \$62 million based on a 10.53% return on equity. The order disallowed future recovery of \$54 million of costs related to the Mountaineer Carbon Capture and Storage Project and allowed the deferral of approximately \$25 million of incremental storm expenses incurred in 2009. As a result, APCo recorded a pretax loss of \$29 million in the second quarter of 2010. In July 2010, APCo filed a petition with the Virginia SCC for reconsideration of the order as it relates to the Mountaineer Carbon

Capture and Storage Project.

West Virginia – In May 2010, APCo and WPCo filed a request with the WVPSC to increase annual base rates by \$156 million based on an 11.75% return on common equity to be effective March 2011. A decision from the WVPSC is expected no later than March 2011.

Turk Plant

SWEP Co is currently constructing the Turk Plant, a new base load 600 MW coal unit in Arkansas, which is expected to be in service in 2012. SWEP Co owns 73% (440 MW) of the Turk Plant and will operate the completed facility. SWEP Co's share of construction costs is currently estimated to cost \$1.3 billion, excluding AFUDC, plus an additional \$131 million for transmission, excluding AFUDC. The APSC, LPSC and PUCT approved SWEP Co's original application to build the Turk Plant. Various proceedings are pending that challenge the Turk Plant's construction and its approved air and wetlands permits. In July 2010, the Arkansas Court of Appeals issued a decision remanding all transmission line CECPN appeals to the APSC. As a result, a stay was not ordered and construction continues on the affected transmission lines.

In June 2010, the Arkansas Supreme Court denied motions for rehearing filed by the APSC and SWEP Co related to the reversal of the APSC's earlier grant of a CECPN for SWEP Co's 88 MW Arkansas portion of the Turk Plant. As a result, in June 2010, SWEP Co filed notice with the APSC of its intent to proceed with construction of the Turk Plant but that SWEP Co no longer intends to pursue a CECPN to seek recovery of its Arkansas portion of Turk Plant Costs in Arkansas retail rates.

In July 2010, the Hempstead County Hunting Club filed a complaint with the Federal District Court for the Western District of Arkansas against SWEP Co, the U.S. Army Corps of Engineers, the U.S. Department of Interior and the U.S. Fish and Wildlife Service seeking an injunction to stop construction of the Turk Plant asserting claims of violations of federal and state laws.

Management expects that SWEP Co will ultimately be able to complete construction of the Turk Plant and related transmission facilities and place those facilities in service. However, if SWEP Co is unable to complete the Turk Plant construction and place the Turk Plant in service or if SWEP Co cannot recover all of its investment in and expenses related to the Turk Plant, it would materially reduce future net income and cash flows and materially impact financial condition.

RESULTS OF OPERATIONS

SEGMENTS

Our reportable segments and their related business activities are as follows:

Utility Operations

- Generation of electricity for sale to U.S. retail and wholesale customers.
- Electricity transmission and distribution in the U.S.

AEP River Operations

- Commercial barging operations that transport coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers.

Generation and Marketing

- Wind farms and marketing and risk management activities primarily in ERCOT.

The table below presents our consolidated Income Before Extraordinary Loss by segment for the three and six months ended June 30, 2010 and 2009.

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|----------------------------------|-----------------------------|-------|---------------------------|-------|
| | 2010 | 2009 | 2010 | 2009 |
| | (in millions) | | | |
| Utility Operations | \$132 | \$327 | \$476 | \$673 |
| AEP River Operations | (1) | 1 | 2 | 12 |
| Generation and Marketing | 7 | 4 | 17 | 28 |
| All Other (a) | (1) | (10) | (12) | (28) |
| Income Before Extraordinary Loss | \$137 | \$322 | \$483 | \$685 |

(a) While not considered a business segment, All Other includes:

- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense, and other nonallocated costs.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts are financial derivatives which gradually settle and completely expire in 2011.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

AEP CONSOLIDATED

Second Quarter of 2010 Compared to Second Quarter of 2009

Income Before Extraordinary Loss in 2010 decreased \$185 million compared to 2009 due to \$185 million of charges incurred (net of tax) in the second quarter of 2010 related to the cost reduction initiatives.

Average basic shares outstanding increased to 479 million in 2010 from 472 million in 2009.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009

Income Before Extraordinary Loss in 2010 decreased \$202 million compared to 2009 primarily due to \$185 million of charges incurred (net of tax) in the second quarter of 2010 related to the cost reduction initiatives.

Average basic shares outstanding increased to 479 million in 2010 from 440 million in 2009 primarily due to the April 2009 issuance of 69 million shares of AEP common stock. Actual shares outstanding were 479 million as of June 30, 2010.

Our results of operations are discussed below by operating segment.

UTILITY OPERATIONS

We believe that a discussion of the results from our Utility Operations segment on a gross margin basis is most appropriate in order to further understand the key drivers of the segment. Gross margin represents utility operating revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances and purchased power.

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|----------------------------------|--------------------------------|---------|------------------------------|---------|
| | 2010 | 2009 | 2010 | 2009 |
| | (in millions) | | | |
| Revenues | \$3,211 | \$3,056 | \$6,637 | \$6,323 |
| Fuel and Purchased Power | 1,110 | 996 | 2,357 | 2,192 |
| Gross Margin | 2,101 | 2,060 | 4,280 | 4,131 |
| Depreciation and Amortization | 394 | 388 | 792 | 761 |
| Other Operating Expenses | 1,314 | 993 | 2,354 | 1,987 |
| Operating Income | 393 | 679 | 1,134 | 1,383 |
| Other Income, Net | 42 | 25 | 85 | 55 |
| Interest Expense | 237 | 227 | 472 | 447 |
| Income Tax Expense | 66 | 150 | 271 | 318 |
| Income Before Extraordinary Loss | \$132 | \$327 | \$476 | \$673 |

Summary of KWH Energy Sales for Utility Operations
For the Three and Six Months Ended June 30, 2010 and 2009

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|-------------------------|--------------------------------|--------|------------------------------|--------|
| | 2010 | 2009 | 2010 | 2009 |
| | (in millions of KWH) | | | |
| Energy/Delivery Summary | | | | |
| Retail: | | | | |
| Residential | 12,659 | 12,391 | 30,433 | 28,762 |
| Commercial | 13,002 | 12,595 | 24,476 | 24,205 |
| Industrial | 14,662 | 13,400 | 28,044 | 26,922 |
| Miscellaneous | 783 | 771 | 1,495 | 1,490 |
| Total Retail (a) | 41,106 | 39,157 | 84,448 | 81,379 |
| Wholesale | 7,019 | 7,166 | 15,156 | 13,943 |
| Total KWHs | 48,125 | 46,323 | 99,604 | 95,322 |

(a) Includes energy delivered to customers served by AEP's Texas Wires Companies.

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on net income. In general, degree day changes in our eastern region have a larger effect on net income than changes in our western region due to the relative size of the two regions and the number of customers within each region.

Summary of Heating and Cooling Degree Days for Utility Operations
For the Three and Six Months Ended June 30, 2010 and 2009

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|----------------------|--------------------------------|------|------------------------------|-------|
| | 2010 | 2009 | 2010 | 2009 |
| | (in degree days) | | | |
| Eastern Region | | | | |
| Actual - Heating (a) | 75 | 156 | 1,975 | 1,977 |
| Normal - Heating (b) | 170 | 171 | 1,911 | 1,962 |
| | | | | |
| Actual - Cooling (c) | 434 | 300 | 434 | 305 |
| Normal - Cooling (b) | 289 | 286 | 293 | 290 |
| | | | | |
| Western Region | | | | |
| Actual - Heating (a) | 5 | 27 | 764 | 540 |
| Normal - Heating (b) | 21 | 21 | 595 | 600 |
| | | | | |
| Actual - Cooling (d) | 866 | 861 | 886 | 960 |
| Normal - Cooling (b) | 757 | 756 | 815 | 812 |

- (a) Eastern Region and Western Region heating degree days are calculated on a 55 degree temperature base.
- (b) Normal Heating/Cooling represents the thirty-year average of degree days.
- (c) Eastern Region cooling degree days are calculated on a 65 degree temperature base.
- (d) Western Region cooling degree days are calculated on a 65 degree temperature base for PSO/SWEPCo and a 70 degree temperature base for TCC/TNC.

Second Quarter of 2010 Compared to Second Quarter of 2009

Reconciliation of Second Quarter of 2009 to Second Quarter of 2010
Income from Utility Operations Before Extraordinary Loss
(in millions)

| | | |
|---|----|--------|
| Second Quarter of 2009 | \$ | 327 |
| Changes in Gross Margin: | | |
| Retail Margins | | 115 |
| Off-system Sales | | (12) |
| Transmission Revenues | | (2) |
| Other Revenues | | (60) |
| Total Change in Gross Margin | | 41 |
| Total Expenses and Other: | | |
| Other Operation and Maintenance | | (307) |
| Depreciation and Amortization | | (6) |
| Taxes Other Than Income Taxes | | (14) |
| Interest and Investment Income | | 11 |
| Carrying Costs Income | | 7 |
| Allowance for Equity Funds Used During Construction | | (1) |
| Interest Expense | | (10) |
| Total Expenses and Other | | (320) |
| Income Tax Expense | | 84 |
| Second Quarter of 2010 | \$ | 132 |

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins increased \$115 million primarily due to the following:
 - A \$22 million increase in the recovery of E&R costs in Virginia, construction financing costs in West Virginia and costs related to the Transmission Rate Adjustment Clause in Virginia, a \$13 million increase in the recovery of advanced metering costs in Texas and a \$13 million net increase in rates in our other jurisdictions. These increases in retail margins had corresponding offsets of \$26 million related to cost recovery riders/trackers that were recognized in the other gross margin/other expense line items below.
 - A \$34 million increase in weather-related usage primarily due to a 45% increase in cooling degree days in our eastern region.
 - A \$20 million increase in fuel margins due to higher fuel and purchased power costs recorded in 2009 related to the Cook Plant Unit 1 (Unit 1) shutdown. This increase in fuel margins was offset by a corresponding decrease in Other Revenues as discussed below.

These increases were partially offset by:

·

A \$9 million decrease due to the termination of an I&M unit power agreement.

- Margins from Off-system Sales decreased \$12 million primarily due to lower trading and marketing margins, partially offset by higher physical sales volumes.
- Other Revenues decreased \$60 million primarily due to the Cook Plant accidental outage insurance proceeds of \$46 million, which ended when Unit 1 returned to service in December 2009. I&M reduced customer bills by approximately \$20 million in the second quarter of 2009 for the cost of replacement power resulting from the Unit 1 outage. This decrease in insurance proceeds was offset by a corresponding increase in Retail Margins as discussed above.

Total Expenses and Other and Income Taxes changed between years as follows:

- Other Operation and Maintenance expenses increased \$307 million primarily due to the following:
 - A \$278 million increase due to expenses related to the cost reduction initiatives in the second quarter of 2010.
 - A \$54 million increase due to the write-off of APCo's Virginia share of the Mountaineer Carbon Capture and Storage Project as denied for recovery by the Virginia SCC.
 - A \$27 million increase in demand side management, energy efficiency, vegetation management programs and other costs which have associated cost recovery riders/trackers that were recognized in retail revenues.

These increases were partially offset by:

- A \$25 million decrease due to the deferral of 2009 storm costs as allowed by the Virginia SCC.
- A \$14 million decrease in plant outage and other plant operating and maintenance expenses.
- Depreciation and Amortization increased \$6 million primarily due to new environmental improvements placed in service and other increases in depreciable property balances.
- Taxes Other Than Income Taxes increased \$14 million primarily due to the employer portion of payroll taxes incurred related to the cost reduction initiatives in the second quarter of 2010.
- Interest and Investment Income increased \$11 million primarily due to the second quarter 2009 write-off of other-than-temporary losses related to equity investments made by EIS.
- Carrying Costs Income increased \$7 million primarily due to increased environmental deferrals in Virginia and a higher under-recovered fuel balance for OPCo.
- Interest Expense increased \$10 million primarily due to an increase in long-term debt.
- Income Tax Expense decreased \$84 million primarily due to a decrease in pretax book income.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009

Reconciliation of Six Months Ended June 30, 2009 to Six Months Ended June 30, 2010
Income from Utility Operations Before Extraordinary Loss
(in millions)

| | | |
|---|----|-------|
| Six Months Ended June 30, 2009 | \$ | 673 |
| Changes in Gross Margin: | | |
| Retail Margins | | 283 |
| Off-system Sales | | 1 |
| Transmission Revenues | | 8 |
| Other Revenues | | (143) |
| Total Change in Gross Margin | | 149 |
| Total Expenses and Other: | | |
| Other Operation and Maintenance | | (344) |
| Depreciation and Amortization | | (31) |
| Taxes Other Than Income Taxes | | (23) |
| Interest and Investment Income | | 8 |
| Carrying Costs Income | | 12 |
| Allowance for Equity Funds Used During Construction | | 7 |
| Interest Expense | | (25) |
| Equity Earnings of Unconsolidated Subsidiaries | | 3 |
| Total Expenses and Other | | (393) |
| Income Tax Expense | | 47 |
| Six Months Ended June 30, 2010 | \$ | 476 |

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins increased \$283 million primarily due to the following:
 - A \$75 million increase in the recovery of E&R costs in Virginia, construction financing costs in West Virginia and costs related to the Transmission Rate Adjustment Clause in Virginia, a \$25 million increase in the recovery of advanced metering costs in Texas, a \$19 million rate increase in Oklahoma, a \$17 million net rate increase for I&M, a \$13 million net increase in rates for SWEPCo and a \$27 million net increase in rates in our other jurisdictions. These increases in retail margins had corresponding offsets of \$64 million related to cost recovery riders/trackers that were recognized in the other gross margin/other expense line items below.
 - A \$71 million increase in weather-related usage primarily due to a 43% increase in cooling degree days in our eastern region and a 41% increase in heating degree days in our western region.
 - A \$42 million increase in fuel margins due to higher fuel and purchased power costs recorded in 2009 related to the Unit 1 shutdown. This increase

in fuel margins was offset by a corresponding decrease in Other Revenues as discussed below.

These increases were partially offset by:

- A \$17 million decrease due to the termination of an I&M unit power agreement.
- Transmission Revenues increased \$8 million primarily due to increased revenues in the ERCOT, PJM and SPP regions.
- Other Revenues decreased \$143 million primarily due to the Cook Plant accidental outage insurance proceeds of \$99 million which ended when Unit 1 returned to service in December 2009. I&M reduced customer bills by approximately \$42 million in the first six months of 2009 for the cost of replacement power resulting from the Unit 1 outage. This decrease in insurance proceeds was offset by a corresponding increase in Retail Margins as discussed above. Other Revenues also decreased due to lower gains on sales of emission allowances of \$23 million.

Total Expenses and Other and Income Taxes changed between years as follows:

- Other Operation and Maintenance expenses increased \$344 million primarily due to the following:
 - A \$278 million increase due to expenses related to the cost reduction initiatives in the second quarter of 2010.
 - A \$72 million increase in demand side management, energy efficiency, vegetation management programs and other costs which have associated cost recovery riders/trackers that were recognized in retail revenues.
 - A \$54 million increase due to the write-off of APCo's Virginia share of the Mountaineer Carbon Capture and Storage Project as denied for recovery by the Virginia SCC.

These increases were partially offset by:

- A \$59 million decrease in storm expenses including the deferral of \$25 million of 2009 storm costs as allowed by the Virginia SCC.
- Depreciation and Amortization increased \$31 million primarily due to new environmental improvements placed in service and other increases in depreciable property balances.
- Taxes Other Than Income Taxes increased \$23 million primarily due to the employer portion of payroll taxes incurred related to the cost reduction initiatives in the second quarter of 2010 and higher franchise and property taxes.
- Interest and Investment Income increased \$8 million primarily due to the second quarter 2009 write-off of other-than-temporary losses related to equity investments made by EIS.
- Carrying Costs Income increased \$12 million primarily due to increased environmental deferrals in Virginia and a higher under-recovered fuel balance for OPCo.
- Allowance for Equity Funds Used During Construction increased \$7 million related to construction projects at SWEPCo's Turk Plant and Stall Unit and the reapplication of "Regulated Operations" accounting guidance for the generation portion of SWEPCo's Texas retail jurisdiction effective the second quarter of 2009.
- Interest Expense increased \$25 million primarily due to an increase in long-term debt and a decrease in the debt component of AFUDC due to lower CWIP balances at APCo, CSPCo and OPCo.
- Income Tax Expense decreased \$47 million primarily due to a decrease in pretax book income, partially offset by the regulatory accounting treatment of state income taxes, other book/tax differences which are accounted for on a flow-through basis and the tax treatment associated with the future reimbursement of Medicare Part D retiree prescription drug benefits.

AEP RIVER OPERATIONS

Second Quarter of 2010 Compared to Second Quarter of 2009

Income Before Extraordinary Loss from our AEP River Operations segment decreased from income of \$1 million in 2009 to a loss of \$1 million in 2010 primarily due to expenses related to the cost reduction initiatives, increased interest expense on new long-term debt and increased lease expense on new barge leases.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009

Income Before Extraordinary Loss from our AEP River Operations segment decreased from \$12 million in 2009 to \$2 million in 2010 primarily due to reduced grain loadings, higher fuel and other operating expenses, expenses related to the cost reduction initiatives, interest expense on increased long-term debt, increased lease expense on new barge leases and a gain on the sale of two older towboats in 2009.

GENERATION AND MARKETING

Second Quarter of 2010 Compared to Second Quarter of 2009

Income Before Extraordinary Loss from our Generation and Marketing segment increased from \$4 million in 2009 to \$7 million in 2010 primarily due to favorable marketing contracts in ERCOT and increased income from our wind farm operations.

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Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009

Income Before Extraordinary Loss from our Generation and Marketing segment decreased from \$28 million in 2009 to \$17 million in 2010 primarily due to reduced inception gains from ERCOT marketing activities partially offset by improved plant performance, hedging activities on our generation assets and increased income from our wind farm operations.

ALL OTHER

Second Quarter of 2010 Compared to Second Quarter of 2009

Income Before Extraordinary Loss from All Other increased from a loss of \$10 million in 2009 to a loss of \$1 million in 2010 primarily due to \$16 million in pretax gains (\$10 million, net of tax) on the sale of our remaining 138,000 shares of Intercontinental Exchange, Inc. (ICE) in the second quarter of 2010.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009

Income Before Extraordinary Loss from All Other increased from a loss of \$28 million in 2009 to a loss of \$12 million in 2010 due to \$16 million in pretax gains (\$10 million, net of tax) on the sale of our remaining 138,000 shares of ICE in the second quarter of 2010.

AEP SYSTEM INCOME TAXES

Second Quarter of 2010 Compared to Second Quarter of 2009

Income Tax Expense decreased \$83 million in comparison to 2009 primarily due to a decrease in pretax book income.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009

Income Tax Expense decreased \$55 million in comparison to 2009 primarily due to a decrease in pretax book income, partially offset by the regulatory accounting treatment of state income taxes, other book/tax differences which are accounted for on a flow-through basis and the tax treatment associated with the future reimbursement of Medicare Part D retiree prescription drug benefits.

FINANCIAL CONDITION

We measure our financial condition by the strength of our balance sheet and the liquidity provided by our cash flows.

DEBT AND EQUITY CAPITALIZATION

| | June 30, 2010 | | | December 31, 2009 | | |
|---|---------------|-------|---|-------------------|-------|---|
| | | | | (\$ in millions) | | |
| Long-term Debt, including amounts due within one year | \$17,348 | 53.9 | % | \$17,498 | 56.8 | % |
| Short-term Debt | 1,473 | 4.6 | | 126 | 0.4 | |
| Total Debt | 18,821 | 58.5 | | 17,624 | 57.2 | |
| Preferred Stock of Subsidiaries | 60 | 0.2 | | 61 | 0.2 | |
| AEP Common Equity | 13,269 | 41.3 | | 13,140 | 42.6 | |
| Noncontrolling Interests | 1 | - | | - | - | |
| Total Debt and Equity Capitalization | \$32,151 | 100.0 | % | \$30,825 | 100.0 | % |

Our ratio of debt-to-total capital increased from 57.2% in 2009 to 58.5% in 2010 primarily due to an increase in short-term debt of \$677 million as a result of a change in an accounting standard applicable to our sale of receivables agreement and an increase of \$668 million in commercial paper outstanding.

LIQUIDITY

Liquidity, or access to cash, is an important factor in determining our financial stability. We believe we have adequate liquidity under our existing credit facilities. At June 30, 2010, we had \$3.4 billion in aggregate credit facility commitments to support our operations. Additional liquidity is available from cash from operations and a sale of receivables agreement. We are committed to maintaining adequate liquidity. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include issuance of long-term debt, sale-leaseback or leasing agreements or common stock.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At June 30, 2010, our available liquidity was approximately \$2.9 billion as illustrated in the table below:

| | Amount (in millions) | Maturity |
|--|-------------------------|------------|
| Commercial Paper Backup: | | |
| Revolving Credit Facility | \$ 1,454 | April 2012 |
| Revolving Credit Facility | 1,500 | June 2013 |
| Revolving Credit Facility | 478 | April 2011 |
| Total | 3,432 | |
| Cash and Cash Equivalents | 838 | |
| Total Liquidity Sources | 4,270 | |
| Less: AEP Commercial Paper Outstanding | 787 | |
| Letters of Credit Issued | 626 | |
| Net Available Liquidity | \$ 2,857 | |

We have credit facilities totaling \$3.4 billion, of which two \$1.5 billion credit facilities support our commercial paper program. One of the \$1.5 billion credit facilities allows for the issuance of up to \$750 million as letters of credit. In June 2010, we canceled a facility that was scheduled to mature in March 2011. We also entered a new \$1.5 billion credit facility in June 2010, which matures in 2013, that allows for the issuance of up to \$600 million as letters of credit. In June 2010, we reduced the credit facility that matures in April 2011 from \$627 million to \$478 million which can be utilized for letters of credit or draws.

We use our commercial paper program to meet the short-term borrowing needs of our subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The maximum amount of commercial paper outstanding during 2010 was \$802 million. The weighted-average interest rate for our commercial paper during 2010 was 0.42%.

Securitized Accounts Receivables

In July 2010, we renewed our receivables securitization agreement. The agreement provides a commitment of \$750 million from bank conduits to purchase receivables. A commitment of \$375 million expires in July 2011 and the remaining commitment of \$375 million expires in July 2013.

Debt Covenants and Borrowing Limitations

Our revolving credit agreements contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating our outstanding debt and other capital is contractually defined in our revolving credit agreements. At June 30, 2010, this contractually-defined percentage was 54.8%. Nonperformance under these covenants could result in an event of default under these credit agreements. At June 30, 2010, we complied with all of the covenants contained in these credit agreements. In addition, the acceleration of our payment obligations, or the obligations of certain of our major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of \$50 million, would cause an event of default under these credit agreements and in a majority of our non-exchange traded commodity contracts which would permit the lenders and counterparties to declare the outstanding amounts payable. However, a default under our non-exchange traded commodity contracts does not cause an event of default under our revolving credit agreements.

The revolving credit facilities do not permit the lenders to refuse a draw on either facility if a material adverse change occurs.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. At June 30, 2010, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of \$0.42 per share in July 2010. Future dividends may vary depending upon our profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Our income derives from our common stock equity in the earnings of our utility subsidiaries. Various financing arrangements, charter provisions and regulatory requirements may impose certain restrictions on the ability of our utility subsidiaries to transfer funds to us in the form of dividends. We have the option to defer interest payments on the AEP Junior Subordinated Debentures for one or more periods of up to 10 consecutive years per period. During any period in which we defer interest payments, we may not declare or pay any dividends or distributions on, or redeem, repurchase or acquire, our common stock. We believe that these restrictions will not have a material effect on our cash flows or financial condition or limit any dividend payments in the foreseeable future.

Credit Ratings

Our access to the commercial paper market may depend on our credit ratings. In addition, downgrades in our credit ratings by one of the rating agencies could increase our borrowing costs.

CASH FLOW

Managing our cash flows is a major factor in maintaining our liquidity strength.

| | Six Months Ended June 30, | |
|--|------------------------------|----------|
| | 2010 | 2009 |
| | (in millions) | |
| Cash and Cash Equivalents at Beginning of Period | \$ 490 | \$ 411 |
| Net Cash Flows from Operating Activities | 582 | 857 |
| Net Cash Flows Used for Investing Activities | (992) | (1,478) |
| Net Cash Flows from Financing Activities | 758 | 568 |

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| | | |
|--|--------|--------|
| Net Increase (Decrease) in Cash and Cash Equivalents | 348 | (53) |
| Cash and Cash Equivalents at End of Period | \$ 838 | \$ 358 |

Cash from operations and short-term borrowings provides working capital and allows us to meet other short-term cash needs.

Operating Activities

| | Six Months Ended June 30, | |
|--|------------------------------|--------|
| | 2010 | 2009 |
| | (in millions) | |
| Net Income | \$ 483 | \$ 680 |
| Depreciation and Amortization | 813 | 779 |
| Other | (714) | (602) |
| Net Cash Flows from Operating Activities | \$ 582 | \$ 857 |

Net Cash Flows from Operating Activities were \$582 million in 2010 consisting primarily of Net Income of \$483 million and \$813 million of noncash Depreciation and Amortization. Other includes a \$656 million increase in securitized receivables under the application of new accounting guidance for “Transfers and Servicing” related to our sale of receivables agreement. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Significant changes in other items include an increase in under-recovered fuel primarily due to the deferral of fuel under the FAC in Ohio and higher fuel costs in Oklahoma, accrued tax benefits and the favorable impact of a decrease in fuel inventory. Deferred Income Taxes increased primarily due to the American Recovery and Reinvestment Act of 2009 extending bonus depreciation provisions, a change in tax accounting method and an increase in tax versus book temporary differences from operations.

Net Cash Flows from Operating Activities were \$857 million in 2009 consisting primarily of Net Income of \$680 million and \$779 million of noncash Depreciation and Amortization. Other represents items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Significant changes in other items include the negative impact on cash of an increase in coal inventory reflecting decreased customer demand for electricity as the result of the economic slowdown and an increase in under-recovered fuel primarily due to the deferral of fuel costs in Ohio as a fuel clause was reactivated in 2009.

Investing Activities

| | Six Months Ended June 30, | |
|--|------------------------------|-------------|
| | 2010 | 2009 |
| | (in millions) | |
| Construction Expenditures | \$ (1,104) | \$ (1,547) |
| Acquisitions of Nuclear Fuel | (41) | (152) |
| Proceeds from Sales of Assets | 147 | 240 |
| Other | 6 | (19) |
| Net Cash Flows Used for Investing Activities | \$ (992) | \$ (1,478) |

Net Cash Flows Used for Investing Activities were \$992 million in 2010 primarily due to Construction Expenditures for new generation, environmental and distribution investments. Proceeds from Sales of Assets in 2010 include \$135 million for sales of Texas transmission assets to ETT.

Net Cash Flows Used for Investing Activities were \$1.5 billion in 2009 primarily due to Construction Expenditures for our new generation, environmental and distribution investments. Proceeds from Sales of Assets in 2009 include \$104 million relating to the sale of a portion of Turk Plant to joint owners and \$92 million for sales of transmission assets in Texas to ETT.

Financing Activities

| | Six Months Ended June 30, | |
|--|------------------------------|----------|
| | 2010 | 2009 |
| | (in millions) | |
| Issuance of Common Stock, Net | \$ 42 | \$ 1,688 |
| Issuance/Retirement of Debt, Net | 1,166 | (711) |
| Dividends Paid on Common Stock | (399) | (364) |
| Other | (51) | (45) |
| Net Cash Flows from Financing Activities | \$ 758 | \$ 568 |

Net Cash Flows from Financing Activities were \$758 million in 2010. Our net debt issuances were \$1.2 billion. The net issuances included issuances of \$884 million of notes and \$287 million of pollution control bonds, a \$668 million increase in commercial paper outstanding and retirements of \$1 billion of senior unsecured notes, \$86 million of securitization bonds and \$183 million of pollution control bonds. Our short-term debt securitized by receivables increased \$656 million under the application of new accounting guidance for “Transfers and Servicing” related to our sale of receivables agreement. We paid common stock dividends of \$399 million. See Note 11 – Financing Activities for a complete discussion of long-term debt issuances and retirements.

Net Cash Flows from Financing Activities in 2009 were \$568 million. Issuance of Common Stock, Net of \$1.7 billion is comprised of our issuance of 69 million shares of common stock with net proceeds of \$1.64 billion and additional shares through our dividend reinvestment, employee savings and incentive programs. Our net debt retirements were \$711 million. These retirements included a repayment of \$1.75 billion outstanding under our credit facilities primarily from the proceeds of our common stock issuance and issuances of \$955 million of senior unsecured notes and \$135 million of pollution control bonds.

OFF-BALANCE SHEET ARRANGEMENTS

In prior periods, under a limited set of circumstances, we entered into off-balance sheet arrangements for various reasons including accelerating cash collections, reducing operational expenses and spreading risk of loss to third parties. Our current guidelines restrict the use of off-balance sheet financing entities or structures to traditional operating lease arrangements and transfers of customer accounts receivable that we enter in the normal course of business. The following identifies significant off-balance sheet arrangements:

| | June 30, 2010 | December 31, 2009 |
|--|------------------|----------------------|
| | (in millions) | |
| AEP Credit Accounts Receivable Purchase Commitments | \$ - | \$ 631 |
| Rockport Plant Unit 2 Future Minimum Lease Payments | 1,846 | 1,920 |
| Railcars Maximum Potential Loss From Lease Agreement | 25 | 25 |

Effective January 1, 2010, we record the receivables and debt related to AEP Credit on our Condensed Consolidated Balance Sheet. For complete information on each of these off-balance sheet arrangements see the “Off-balance Sheet Arrangements” section of “Management’s Financial Discussion and Analysis of Results of Operations” in the 2009 Annual Report.

SUMMARY OBLIGATION INFORMATION

A summary of our contractual obligations is included in our 2009 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in “Cash Flow” above.

SIGNIFICANT FACTORS

We continue to be involved in various matters described in the “Significant Factors” section of “Management’s Financial Discussion and Analysis of Results of Operations” in our 2009 Annual Report. The 2009 Annual Report should be read in conjunction with this report in order to understand significant factors which have not materially changed in status since the issuance of our 2009 Annual Report, but may have a material impact on our future net income, cash flows and financial condition.

REGULATORY ISSUES

Ohio Electric Security Plan Filings

During 2009, the PUCO issued an order that modified and approved CSPCo’s and OPCo’s ESPs which established rates through 2011. The order also limits rate increases for CSPCo to 7% in 2009, 6% in 2010 and 6% in 2011 and for OPCo to 8% in 2009, 7% in 2010 and 8% in 2011. The order provides a FAC for the three-year period of the ESP. Several notices of appeal are outstanding at the Supreme Court of Ohio relating to significant issues in the determination of the approved ESP rates. CSPCo and OPCo will file their significantly excessive earnings test with the PUCO by their September 2010 deadline. CSPCo and OPCo are unable to determine whether they will be required to return any of their ESP revenues to customers. See “Ohio Electric Security Plan Filings” section of Note 3.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in a fire on the electric generator. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately \$395 million. Management believes that I&M should recover a significant portion of repair and replacement costs through the turbine vendor’s warranty, insurance and the regulatory process. I&M repaired Unit 1 and it resumed operations in December 2009 at slightly reduced power. The Unit 1 rotors were repaired and reinstalled due to the extensive lead time required to manufacture and install new turbine rotors. As a result, the replacement of the repaired turbine rotors and other equipment is scheduled for the Unit 1 planned outage in the fall of 2011. If the ultimate costs of the incident are not covered by warranty, insurance or through the related regulatory process or if any future regulatory proceedings are adverse, it could have an adverse impact on net income, cash flows and financial condition. See “Cook Plant Unit 1 Fire and Shutdown” section of Note 4.

Texas Restructuring Appeals

Pursuant to PUCT restructuring orders, TCC securitized net recoverable stranded generation costs of \$2.5 billion and is recovering the principal and interest on the securitization bonds through the end of 2020. TCC also refunded other net true-up regulatory liabilities of \$375 million during the period October 2006 through June 2008 via a CTC credit rate rider under PUCT restructuring orders. TCC and intervenors appealed the PUCT’s true-up related orders. After rulings from the Texas District Court and the Texas Court of Appeals, TCC, the PUCT and intervenors filed petitions for review with the Texas Supreme Court. Review is discretionary and the Texas Supreme Court has not yet determined if it will grant review. See “Texas Restructuring Appeals” section of Note 3.

Mountaineer Carbon Capture and Storage Project

APCo and ALSTOM Power, Inc. (Alstom), an unrelated third party, jointly constructed a CO2 capture validation facility, which was placed into service in September 2009. APCo also constructed and owns the necessary facilities to store the CO2. In APCo’s July 2009 Virginia base rate filing and APCo’s May 2010 West Virginia base rate filing, APCo requested recovery of and a return on its estimated increased Virginia and West Virginia jurisdictional share of

its project costs and recovery of the related asset retirement obligation regulatory asset amortization and accretion. In July 2010, the Virginia SCC issued a base rate order that denied recovery of the Virginia share of the Mountaineer Carbon Capture and Storage Project costs, which resulted in a pretax write-off of approximately \$54 million in the second quarter of 2010. In response to the order, APCo filed with the Virginia SCC a petition for

reconsideration of the order as it relates to the Mountaineer Carbon Capture and Storage Project. Through June 30, 2010, APCo has recorded a noncurrent regulatory asset of \$58 million consisting of \$38 million in project costs and \$20 million in asset retirement costs. If APCo cannot recover its remaining investments in and expenses related to the Mountaineer Carbon Capture and Storage project, it would reduce future net income and cash flows and impact financial condition. See “Mountaineer Carbon Capture and Storage Project” section of Note 3.

Turk Plant

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which is expected to be in-service in 2012. SWEPCo owns 73% of the Turk Plant and will operate the completed facility. The Turk Plant is currently estimated to cost \$1.7 billion, excluding AFUDC, plus an additional \$131 million for transmission, excluding AFUDC. SWEPCo’s share is currently estimated to cost \$1.3 billion, excluding AFUDC, plus an additional \$131 million for transmission, excluding AFUDC. Notices of appeal are outstanding at the Arkansas Court of Appeals and the Circuit Court of Hempstead County, Arkansas. Matters are also outstanding at the LPSC, the Texas Court of Appeals and the Federal District Court for the Western District of Arkansas. See “Turk Plant” section of Note 3.

LITIGATION

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot state what the eventual resolution will be or the timing and amount of any loss, fine or penalty may be. We assess the probability of loss for each contingency and accrue a liability for cases that have a probable likelihood of loss if the loss can be estimated. For details on our regulatory proceedings and pending litigation see Note 4 – Rate Matters, Note 6 – Commitments, Guarantees and Contingencies and the “Litigation” section of “Management’s Financial Discussion and Analysis of Results of Operations” in the 2009 Annual Report. Additionally, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies included herein. Adverse results in these proceedings have the potential to materially affect our net income.

ENVIRONMENTAL ISSUES

We are implementing a substantial capital investment program and incurring additional operational costs to comply with new environmental control requirements. We anticipate making additional investments and operational changes. The most significant sources are the existing and anticipated CAA requirements to reduce emissions of SO₂, NO_x, PM and hazardous air pollutants from fossil fuel-fired power plants and new proposals governing the beneficial use and disposal of coal combustion products.

We are engaged in litigation about environmental issues, have been notified of potential responsibility for the clean-up of contaminated sites and incur costs for disposal of SNF and future decommissioning of our nuclear units. We are also engaged in the development of possible future requirements to reduce CO₂ emissions to address concerns about global climate change. See a complete discussion of these matters in the “Environmental Matters” section of “Management’s Financial Discussion and Analysis of Results of Operations” in the 2009 Annual Report.

Clean Air Act Transport Rule (Transport Rule)

In July 2010, the Federal EPA issued a proposed rule to replace the Clean Air Interstate Rule (CAIR) that would impose new and more stringent requirements to control SO₂ and NO_x emissions from fossil fuel-fired electric generating units in 31 states and the District of Columbia. Each state covered by the Transport Rule is assigned an allowance budget for SO₂ and/or NO_x. Limited interstate trading is allowed on a sub-regional basis and intrastate trading is allowed among generating units. Certain of our western states (Texas, Arkansas and Oklahoma) would be

subject to only the seasonal NOx program, with new limits that are proposed to take effect in 2012. The remainder of the states in which we operate would be subject to seasonal and annual NOx programs and an annual SO2 emissions reduction program that takes effect in two phases. The first phase becomes effective in 2012 and requires approximately 1 million tons per year more SO2 emission reductions across the region than would have been required under CAIR. The second phase takes effect in 2014 and reduces emissions by an additional 800,000 tons per year. The SO2 and NOx programs rely on newly-created allowances rather than relying on the CAIR NOx allowances or the Title IV Acid Rain Program allowances used in the CAIR rule. The time frames for and

stringency of the additional emission reductions, coupled with the lack of robust interstate trading and the elimination of historic allowance banks, pose significant concerns for the AEP System and our electric utility customers, as these features could accelerate unit retirements, increase capital requirements, constrain operations and decrease reliability. Comments on the proposed rule will be due within 60 days after publication in the Federal Register.

Coal Combustion Residual Rule

In June 2010, the Federal EPA published a proposed rule to regulate the disposal and beneficial re-use of coal combustion residuals, including fly ash and bottom ash generated at our coal-fired electric generating units. The rule contains two alternative proposals, one that would impose federal hazardous waste disposal and management standards on these materials and one that would allow states to retain primary authority to regulate the beneficial re-use and disposal of these materials under state solid waste management standards, including minimum federal standards for disposal and management. Both proposals would impose stringent requirements for the construction of new coal ash landfills and would require existing unlined surface impoundments to upgrade to the new standards or stop receiving coal ash and initiate closure within five years of the issuance of a final rule.

Currently, approximately 40% of the coal ash and other residual products from our generating facilities are re-used in the production of cement and wallboard, as structural fill or soil amendments, as abrasives or road treatment materials and for other beneficial uses. Certain of these uses would no longer be available and others are likely to significantly decline if coal ash and related materials are classified as hazardous wastes. In addition, we currently use surface impoundments and landfills to manage these materials at our generating facilities and will incur significant costs to upgrade or close and replace these existing facilities. We are currently studying the potential costs associated with this proposal and expect that it will impose significant costs. We will seek recovery of expenditures for pollution control technologies and associated costs from customers through our regulated rates (in regulated jurisdictions). We should be able to recover these expenditures through market prices in deregulated jurisdictions. If not, these costs could adversely affect future net income, cash flows and possibly financial condition.

Global Warming

While comprehensive economy-wide regulation of CO₂ emissions might be achieved through new legislation, Congress has yet to enact such legislation. The Federal EPA continues to take action to regulate CO₂ emissions under the existing requirements of the CAA. The Federal EPA issued a final endangerment finding for CO₂ emissions from new motor vehicles in December 2009 and final rules for new motor vehicles in May 2010. The Federal EPA determined that CO₂ emissions from stationary sources will be subject to regulation under the CAA beginning in January 2011 at the earliest and finalized its proposed scheme to streamline and phase-in regulation of stationary source CO₂ emissions through the NSR prevention of significant deterioration and Title V operating permit programs. The Federal EPA is reconsidering whether to include CO₂ emissions in a number of stationary source standards, including standards that apply to new and modified electric utility units.

Our fossil fuel-fired generating units are very large sources of CO₂ emissions. If substantial CO₂ emission reductions are required, there will be significant increases in capital expenditures and operating costs which would impact the ultimate retirement of older, less-efficient, coal-fired units. To the extent we install additional controls on our generating plants to limit CO₂ emissions and receive regulatory approvals to increase our rates, cost recovery could have a positive effect on future earnings. Prudently incurred capital investments made by our subsidiaries in rate-regulated jurisdictions to comply with legal requirements and benefit customers are generally included in rate base for recovery and earn a return on investment. We would expect these principles to apply to investments made to address new environmental requirements. However, requests for rate increases reflecting these costs can affect us adversely because our regulators could limit the amount or timing of increased costs that we would recover through higher rates. In addition, to the extent our costs are relatively higher than our competitors' costs, such as operators of nuclear generation, it could reduce our off-system sales or cause us to lose customers in jurisdictions that permit

customers to choose their supplier of generation service.

Several states have adopted programs that directly regulate CO₂ emissions from power plants, but none of these programs are currently in effect in states where we have generating facilities. Certain states, including Ohio, Michigan, Texas and Virginia, passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements. We are taking steps to comply with these requirements.

Certain groups have filed lawsuits alleging that emissions of CO₂ are a “public nuisance” and seeking injunctive relief and/or damages from small groups of coal-fired electricity generators, petroleum refiners and marketers, coal companies and others. We have been named in pending lawsuits, which we are vigorously defending. It is not possible to predict the outcome of these lawsuits or their impact on our operations or financial condition. See “Carbon Dioxide Public Nuisance Claims” and “Alaskan Villages’ Claims” sections of Note 4.

Future federal and state legislation or regulations that mandate limits on the emission of CO₂ would result in significant increases in capital expenditures and operating costs, which in turn, could lead to increased liquidity needs and higher financing costs. Excessive costs to comply with future legislation or regulations might force our utility subsidiaries to close some coal-fired facilities and could lead to possible impairment of assets. As a result, mandatory limits could have a material adverse impact on our net income, cash flows and financial condition.

For detailed information on global warming and the actions we are taking to address potential impacts, see Part I of the 2009 Form 10-K under the headings entitled “Business – General – Environmental and Other Matters – Global Warming” and “Management’s Financial Discussion and Analysis of Results of Operations.”

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

See the “Critical Accounting Policies and Estimates” section of “Management’s Financial Discussion and Analysis of Results of Operations” in the 2009 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting pronouncements.

NEW ACCOUNTING PRONOUNCEMENTS

New Accounting Pronouncements Adopted During 2010

We adopted ASU 2009-16 “Transfers and Servicing” effective January 1, 2010. The adoption of this standard resulted in AEP Credit’s transfers of receivables being accounted for as financings with the receivables and short-term debt recorded on our balance sheet.

We adopted the prospective provisions of ASU 2009-17 “Consolidations” effective January 1, 2010. We no longer consolidate DHLHC effective with the adoption of this standard.

See Note 2 for further discussion of accounting pronouncements.

Future Accounting Changes

The FASB’s standard-setting process is ongoing and until new standards have been finalized and issued, we cannot determine the impact on the reporting of our operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, contingencies, financial instruments, emission allowances, fair value measurements, leases, insurance, hedge accounting, consolidation policy and discontinued operations. We also expect to see more FASB projects as a result of its desire to converge

International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on our future net income and financial position.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

Our Utility Operations segment is exposed to certain market risks as a major power producer and marketer of wholesale electricity, coal and emission allowances. These risks include commodity price risk, interest rate risk and credit risk. In addition, we are exposed to foreign currency exchange risk because occasionally we procure various services and materials used in our energy business from foreign suppliers. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

Our Generation and Marketing segment, operating primarily within ERCOT, transacts in wholesale energy trading and marketing contracts. This segment is exposed to certain market risks as a marketer of wholesale electricity. These risks include commodity price risk, interest rate risk and credit risk. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

All Other includes natural gas operations which holds forward natural gas contracts that were not sold with the natural gas pipeline and storage assets. These contracts are financial derivatives, which gradually settle and completely expire in 2011. Our risk objective is to keep these positions generally risk neutral through maturity.

We employ risk management contracts including physical forward purchase and sale contracts and financial forward purchase and sale contracts. We engage in risk management of electricity, coal, natural gas and emission allowances and to a lesser degree other commodities associated with our energy business. As a result, we are subject to price risk. The amount of risk taken is determined by the commercial operations group in accordance with the market risk policy approved by the Finance Committee of our Board of Directors. Our market risk oversight staff independently monitors our risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (CORC) various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The CORC consists of our Executive Vice President - Generation, Chief Financial Officer, Senior Vice President of Commercial Operations and Chief Risk Officer. When commercial activities exceed predetermined limits, we modify the positions to reduce the risk to be within the limits unless specifically approved by the CORC.

The following table summarizes the reasons for changes in total mark-to-market (MTM) value as compared to December 31, 2009:

| MTM Risk Management Contract Net Assets (Liabilities) | | | | |
|--|-----------------------|--------------------------------|-----------|--------|
| Six Months Ended June 30, 2010 | | | | |
| (in millions) | | | | |
| | Utility Operations | Generation and Marketing | All Other | Total |
| Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2009 | \$ 134 | \$ 147 | \$ (3) | \$ 278 |
| (Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period | (39) | (9) | 3 | (45) |
| Fair Value of New Contracts at Inception When Entered During the Period (a) | 8 | 8 | - | 16 |
| Net Option Premiums Received for Unexercised or Unexpired Option Contracts Entered During the Period | (1) | - | - | (1) |
| Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts (b) | (2) | (2) | - | (4) |
| Changes in Fair Value Due to Market Fluctuations During the Period (c) | 10 | 6 | - | 16 |
| Changes in Fair Value Allocated to Regulated Jurisdictions (d) | 22 | - | - | 22 |
| Total MTM Risk Management Contract Net Assets at June 30, 2010 | \$ 132 | \$ 150 | \$ - | 282 |
| Cash Flow Hedge Contracts | | | | (2) |
| Fair Value Hedge Contracts | | | | 4 |
| Collateral Deposits | | | | 77 |
| Total MTM Derivative Contract Net Assets at June 30, 2010 | | | | \$ 361 |

(a) Reflects fair value on long-term structured contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.

(b) Reflects changes in methodology in calculating the credit and discounting liability fair value adjustments.

(c) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.

(d) Relates to the net gains (losses) of those contracts that are not reflected on the Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory

liabilities/assets.

See Note 8 – Derivatives and Hedging and Note 9 – Fair Value Measurements for additional information related to our risk management contracts. The following tables and discussion provide information on our credit risk and market volatility risk.

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Credit Risk

We limit credit risk in our wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. We use Moody's Investors Service, Standard & Poor's and current market-based qualitative and quantitative data to assess the financial health of counterparties on an ongoing basis. If an external rating is not available, an internal rating is generated utilizing a quantitative tool developed by Moody's to estimate probability of default that corresponds to an implied external agency credit rating.

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. As of June 30, 2010, our credit exposure net of collateral to sub investment grade counterparties was approximately 8.0%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of June 30, 2010, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable:

| Counterparty Credit Quality | Exposure Before Credit Collateral | Credit Collateral (in millions, except number of counterparties) | Net Exposure | Number of Counterparties >10% of Net Exposure | Net Exposure of Counterparties >10% |
|---------------------------------|--|---|-----------------|--|--|
| Investment Grade | \$ 717 | \$ 46 | \$ 671 | 1 | \$ 152 |
| Split Rating | 4 | - | 4 | 1 | 4 |
| Noninvestment Grade | 3 | 1 | 2 | 4 | 2 |
| No External Ratings: | | | | | |
| Internal Investment Grade | 145 | - | 145 | 3 | 100 |
| Internal Noninvestment Grade | 82 | 11 | 71 | 3 | 63 |
| Total as of June 30, 2010 | \$ 951 | \$ 58 | \$ 893 | 12 | \$ 321 |
| Total as of December 31, 2009 | \$ 846 | \$ 58 | \$ 788 | 12 | \$ 317 |

Value at Risk (VaR) Associated with Risk Management Contracts

We use a risk measurement model, which calculates VaR, to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, as of June 30, 2010, a near term typical change in commodity prices is not expected to have a material effect on our net income, cash flows or financial condition.

The following table shows the end, high, average and low market risk as measured by VaR for the periods indicated:

VaR Model

| Six Months Ended June 30, 2010 (in millions) | | | | Twelve Months Ended December 31, 2009 (in millions) | | | |
|--|------|---------|-----|---|------|---------|-----|
| End | High | Average | Low | End | High | Average | Low |
| \$1 | \$2 | \$1 | \$- | \$1 | \$2 | \$1 | \$- |

We back-test our VaR results against performance due to actual price movements. Based on the assumed 95% confidence interval, the performance due to actual price movements would be expected to exceed the VaR at least once every 20 trading days.

As our VaR calculation captures recent price movements, we also perform regular stress testing of the portfolio to understand our exposure to extreme price movements. We employ a historical-based method whereby the current portfolio is subjected to actual, observed price movements from the last four years in order to ascertain which historical price movements translated into the largest potential MTM loss. We then research the underlying positions, price moves and market events that created the most significant exposure and report the findings to the Risk Executive Committee or the CORC as appropriate.

Interest Rate Risk

We utilize an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which AEP's interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on debt outstanding as of June 30, 2010 and December 31, 2009, the estimated EaR on our debt portfolio for the following twelve months was \$3 million and \$4 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

For the Three and Six Months Ended June 30, 2010 and 2009

(in millions, except per-share and share amounts)

(Unaudited)

| | Three Months Ended | | Six Months Ended | |
|---|--------------------|--------------|------------------|--------------|
| | 2010 | 2009 | 2010 | 2009 |
| REVENUES | | | | |
| Utility Operations | \$3,186 | \$3,035 | \$6,592 | \$6,302 |
| Other Revenues | 174 | 167 | 337 | 358 |
| TOTAL REVENUES | 3,360 | 3,202 | 6,929 | 6,660 |
| EXPENSES | | | | |
| Fuel and Other Consumables Used for Electric Generation | 895 | 764 | 1,909 | 1,693 |
| Purchased Electricity for Resale | 227 | 258 | 465 | 553 |
| Other Operation | 994 | 638 | 1,667 | 1,248 |
| Maintenance | 243 | 271 | 514 | 566 |
| Depreciation and Amortization | 405 | 397 | 813 | 779 |
| Taxes Other Than Income Taxes | 202 | 192 | 409 | 389 |
| TOTAL EXPENSES | 2,966 | 2,520 | 5,777 | 5,228 |
| OPERATING INCOME | 394 | 682 | 1,152 | 1,432 |
| Other Income (Expense): | | | | |
| Interest and Investment Income (Loss) | 18 | (5) | 21 | - |
| Carrying Costs Income | 19 | 12 | 33 | 21 |
| Allowance for Equity Funds Used During Construction | 19 | 20 | 43 | 36 |
| Interest Expense | (249) | (240) | (499) | (478) |
| INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS | 201 | 469 | 750 | 1,011 |
| Income Tax Expense | 65 | 148 | 272 | 327 |
| Equity Earnings of Unconsolidated Subsidiaries | 1 | 1 | 5 | 1 |
| INCOME BEFORE EXTRAORDINARY LOSS | 137 | 322 | 483 | 685 |
| EXTRAORDINARY LOSS, NET OF TAX | - | (5) | - | (5) |
| NET INCOME | 137 | 317 | 483 | 680 |
| Less: Net Income Attributable to Noncontrolling Interests | | | | |
| | 1 | 1 | 2 | 3 |
| NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS | 136 | 316 | 481 | 677 |

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Less: Preferred Stock Dividend Requirements of
Subsidiaries

- - 1 1

EARNINGS ATTRIBUTABLE TO AEP
COMMON SHAREHOLDERS

\$136 \$316 \$480 \$676

WEIGHTED AVERAGE NUMBER OF BASIC
AEP COMMON SHARES OUTSTANDING

479,050,774 472,220,041 478,741,871 439,703,968

BASIC EARNINGS (LOSS) PER SHARE
ATTRIBUTABLE TO AEP COMMON
SHAREHOLDERS

| | | | | |
|----------------------------------|--------|---------|--------|---------|
| Income Before Extraordinary Loss | \$0.28 | \$0.68 | \$1.00 | \$1.55 |
| Extraordinary Loss, Net of Tax | - | (0.01) | - | (0.01) |

TOTAL BASIC EARNINGS PER SHARE
ATTRIBUTABLE TO AEP COMMON
SHAREHOLDERS

\$0.28 \$0.67 \$1.00 \$1.54

WEIGHTED AVERAGE NUMBER OF DILUTED
AEP COMMON SHARES OUTSTANDING

479,176,543 472,222,817 479,012,304 439,983,030

DILUTED EARNINGS (LOSS) PER SHARE
ATTRIBUTABLE TO AEP COMMON
SHAREHOLDERS

| | | | | |
|----------------------------------|--------|---------|--------|---------|
| Income Before Extraordinary Loss | \$0.28 | \$0.68 | \$1.00 | \$1.55 |
| Extraordinary Loss, Net of Tax | - | (0.01) | - | (0.01) |

TOTAL DILUTED EARNINGS PER SHARE
ATTRIBUTABLE TO AEP COMMON
SHAREHOLDERS

\$0.28 \$0.67 \$1.00 \$1.54

CASH DIVIDENDS PAID PER SHARE

\$0.42 \$0.41 \$0.83 \$0.82

See Condensed Notes to Condensed Consolidated
Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY AND
COMPREHENSIVE INCOME (LOSS)

For the Six Months Ended June 30, 2010 and 2009

(in millions)

(Unaudited)

| | AEP Common Shareholders | | Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Noncontrolling Interests | Total |
|---|-------------------------|----------|--------------------|----------------------|---|-----------------------------|-----------|
| | Common Stock Shares | Amount | | | | | |
| TOTAL EQUITY – DECEMBER 31, 2008 | 426 | \$ 2,771 | \$ 4,527 | \$ 3,847 | \$ (452) | \$ 17 | \$ 10,710 |
| Issuance of Common Stock | 71 | 460 | 1,278 | | | | 1,738 |
| Common Stock Dividends | | | | (363) | | (3) | (366) |
| Preferred Stock Dividend Requirements of Subsidiaries | | | | (1) | | | (1) |
| Other Changes in Equity | | | (50) | | | 1 | (49) |
| SUBTOTAL – EQUITY | | | | | | | 12,032 |
| COMPREHENSIVE INCOME | | | | | | | |
| Other Comprehensive Income (Loss), Net of Taxes: | | | | | | | |
| Cash Flow Hedges, Net of Tax of \$9 | | | | | 17 | | 17 |
| Securities Available for Sale, Net of Tax of \$5 | | | | | 9 | | 9 |
| Amortization of Pension and OPEB Deferred Costs, Net of Tax of \$14 | | | | | 25 | | 25 |
| NET INCOME | | | | 677 | | 3 | 680 |
| TOTAL COMPREHENSIVE INCOME | | | | | | | 731 |
| TOTAL EQUITY – JUNE 30, 2009 | 497 | \$ 3,231 | \$ 5,755 | \$ 4,160 | \$ (401) | \$ 18 | \$ 12,763 |
| TOTAL EQUITY – DECEMBER 31, 2009 | 498 | \$ 3,239 | \$ 5,824 | \$ 4,451 | \$ (374) | \$ - | \$ 13,140 |
| | 2 | 9 | 34 | | | | 43 |

| | | | |
|---|--------|------|---------------|
| Issuance of Common Stock | | | |
| Common Stock Dividends | (398) | (1) | (399) |
| Preferred Stock Dividend Requirements of Subsidiaries | (1) | | (1) |
| Other Changes in Equity | 2 | | 2 |
| SUBTOTAL – EQUITY | | | 12,785 |

COMPREHENSIVE INCOME

| | | | |
|--|------------|----------|------------|
| Other Comprehensive Income (Loss), Net of Taxes: | | | |
| Cash Flow Hedges, Net of Tax of \$1 | 2 | | 2 |
| Securities Available for Sale, Net of Tax of \$6 | (11) | | (11) |
| Amortization of Pension and OPEB Deferred Costs, Net of Tax of \$6 | 11 | | 11 |
| NET INCOME | 481 | 2 | 483 |
| TOTAL COMPREHENSIVE INCOME | | | 485 |

| | | | | | | | |
|-------------------------------------|------------|-----------------|-----------------|-----------------|------------------|-------------|------------------|
| TOTAL EQUITY – JUNE 30, 2010 | 500 | \$ 3,248 | \$ 5,860 | \$ 4,533 | \$ (372) | \$ 1 | \$ 13,270 |
|-------------------------------------|------------|-----------------|-----------------|-----------------|------------------|-------------|------------------|

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS

ASSETS

June 30, 2010 and December 31, 2009

(in millions)

(Unaudited)

| | 2010 | 2009 |
|--|-----------------|-----------------|
| CURRENT ASSETS | | |
| Cash and Cash Equivalents | \$838 | \$490 |
| Other Temporary Investments | 298 | 363 |
| Accounts Receivable: | | |
| Customers | 651 | 492 |
| Accrued Unbilled Revenues | 115 | 503 |
| Pledged Accounts Receivable - AEP Credit | 1,011 | - |
| Miscellaneous | 114 | 92 |
| Allowance for Uncollectible Accounts | (44) | (37) |
| Total Accounts Receivable | 1,847 | 1,050 |
| Fuel | 984 | 1,075 |
| Materials and Supplies | 593 | 586 |
| Risk Management Assets | 250 | 260 |
| Accrued Tax Benefits | 653 | 547 |
| Regulatory Asset for Under-Recovered Fuel Costs | 104 | 85 |
| Margin Deposits | 74 | 89 |
| Prepayments and Other Current Assets | 152 | 211 |
| TOTAL CURRENT ASSETS | 5,793 | 4,756 |
| PROPERTY, PLANT AND EQUIPMENT | | |
| Electric: | | |
| Production | 23,930 | 23,045 |
| Transmission | 8,420 | 8,315 |
| Distribution | 13,799 | 13,549 |
| Other Property, Plant and Equipment (including coal mining and nuclear fuel) | 3,820 | 3,744 |
| Construction Work in Progress | 2,431 | 3,031 |
| Total Property, Plant and Equipment | 52,400 | 51,684 |
| Accumulated Depreciation and Amortization | 17,682 | 17,340 |
| TOTAL PROPERTY, PLANT AND EQUIPMENT - NET | 34,718 | 34,344 |
| OTHER NONCURRENT ASSETS | | |
| Regulatory Assets | 4,732 | 4,595 |
| Securitized Transition Assets | 1,834 | 1,896 |
| Spent Nuclear Fuel and Decommissioning Trusts | 1,391 | 1,392 |
| Goodwill | 76 | 76 |
| Long-term Risk Management Assets | 408 | 343 |
| Deferred Charges and Other Noncurrent Assets | 985 | 946 |
| TOTAL OTHER NONCURRENT ASSETS | 9,426 | 9,248 |
| TOTAL ASSETS | \$49,937 | \$48,348 |

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
June 30, 2010 and December 31, 2009
(Unaudited)

| | 2010 | 2009 |
|--|---------------|-------------|
| | (in millions) | |
| CURRENT LIABILITIES | | |
| Accounts Payable | \$ 863 | \$ 1,158 |
| Short-term Debt: | | |
| General | 796 | 126 |
| Securitized Debt for Receivables - AEP Credit | 677 | - |
| Total Short-term Debt | 1,473 | 126 |
| Long-term Debt Due Within One Year | 1,043 | 1,741 |
| Risk Management Liabilities | 120 | 120 |
| Customer Deposits | 266 | 256 |
| Accrued Taxes | 570 | 632 |
| Accrued Interest | 284 | 287 |
| Regulatory Liability for Over-Recovered Fuel Costs | 27 | 76 |
| Other Current Liabilities | 1,132 | 931 |
| TOTAL CURRENT LIABILITIES | 5,778 | 5,327 |
| NONCURRENT LIABILITIES | | |
| Long-term Debt | 16,305 | 15,757 |
| Long-term Risk Management Liabilities | 177 | 128 |
| Deferred Income Taxes | 6,671 | 6,420 |
| Regulatory Liabilities and Deferred Investment Tax Credits | 3,017 | 2,909 |
| Asset Retirement Obligations | 1,280 | 1,254 |
| Employee Benefits and Pension Obligations | 2,107 | 2,189 |
| Deferred Credits and Other Noncurrent Liabilities | 1,272 | 1,163 |
| TOTAL NONCURRENT LIABILITIES | 30,829 | 29,820 |
| TOTAL LIABILITIES | 36,607 | 35,147 |
| Cumulative Preferred Stock Not Subject to Mandatory Redemption | 60 | 61 |
| Rate Matters (Note 3) | | |
| Commitments and Contingencies (Note 4) | | |
| EQUITY | | |
| Common Stock – Par Value – \$6.50 Per Share: | | |
| | 2010 | 2009 |
| Shares | | |
| Authorized | 600,000,000 | 600,000,000 |
| Shares Issued | 499,655,121 | 498,333,265 |
| (20,278,858 shares were held in treasury at June 30, 2010 and December 31, 2009) | 3,248 | 3,239 |
| Paid-in Capital | 5,860 | 5,824 |
| Retained Earnings | 4,533 | 4,451 |

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| | | |
|---|-----------|-----------|
| Accumulated Other Comprehensive Income (Loss) | (372) | (374) |
| TOTAL AEP COMMON SHAREHOLDERS' EQUITY | 13,269 | 13,140 |
| Noncontrolling Interests | 1 | - |
| TOTAL EQUITY | 13,270 | 13,140 |
| TOTAL LIABILITIES AND EQUITY | \$ 49,937 | \$ 48,348 |

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Six Months Ended June 30, 2010 and 2009

(in millions)

(Unaudited)

| | 2010 | 2009 |
|--|----------|----------|
| OPERATING ACTIVITIES | | |
| Net Income | \$483 | \$680 |
| Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities: | | |
| Depreciation and Amortization | 813 | 779 |
| Deferred Income Taxes | 212 | 360 |
| Extraordinary Loss, Net of Tax | - | 5 |
| Carrying Costs Income | (33) | (21) |
| Allowance for Equity Funds Used During Construction | (43) | (36) |
| Mark-to-Market of Risk Management Contracts | 4 | (83) |
| Amortization of Nuclear Fuel | 69 | 25 |
| Property Taxes | 54 | 38 |
| Fuel Over/Under-Recovery, Net | (181) | (246) |
| Change in Other Noncurrent Assets | (21) | (11) |
| Change in Other Noncurrent Liabilities | 65 | 84 |
| Changes in Certain Components of Working Capital: | | |
| Accounts Receivable, Net | (802) | 29 |
| Fuel, Materials and Supplies | 71 | (313) |
| Margin Deposits | 15 | (49) |
| Accounts Payable | (168) | 18 |
| Customer Deposits | 9 | 17 |
| Accrued Taxes, Net | (164) | (110) |
| Accrued Interest | (3) | 3 |
| Other Current Assets | 51 | (25) |
| Other Current Liabilities | 151 | (287) |
| Net Cash Flows from Operating Activities | 582 | 857 |
| INVESTING ACTIVITIES | | |
| Construction Expenditures | (1,104) | (1,547) |
| Change in Other Temporary Investments, Net | 31 | 43 |
| Purchases of Investment Securities | (838) | (443) |
| Sales of Investment Securities | 849 | 411 |
| Acquisitions of Nuclear Fuel | (41) | (152) |
| Acquisitions of Assets | (12) | (11) |
| Proceeds from Sales of Assets | 147 | 240 |
| Other Investing Activities | (24) | (19) |
| Net Cash Flows Used for Investing Activities | (992) | (1,478) |
| FINANCING ACTIVITIES | | |
| Issuance of Common Stock, Net | 42 | 1,688 |
| Issuance of Long-term Debt | 1,161 | 1,075 |
| Borrowings from Revolving Credit Facilities | 50 | 59 |
| Change in Short-term Debt, Net | 1,345 | 328 |

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| | | |
|--|----------|----------|
| Retirement of Long-term Debt | (1,341) | (372) |
| Repayments to Revolving Credit Facilities | (49) | (1,801) |
| Principal Payments for Capital Lease Obligations | (49) | (42) |
| Dividends Paid on Common Stock | (399) | (364) |
| Dividends Paid on Cumulative Preferred Stock | (1) | (1) |
| Other Financing Activities | (1) | (2) |
| Net Cash Flows from Financing Activities | 758 | 568 |
| Net Increase (Decrease) in Cash and Cash Equivalents | 348 | (53) |
| Cash and Cash Equivalents at Beginning of Period | 490 | 411 |
| Cash and Cash Equivalents at End of Period | \$838 | \$358 |

SUPPLEMENTARY INFORMATION

| | | |
|--|-------|-------|
| Cash Paid for Interest, Net of Capitalized Amounts | \$487 | \$495 |
| Net Cash Paid for Income Taxes | 174 | 27 |
| Noncash Acquisitions Under Capital Leases | 176 | 17 |
| Construction Expenditures Included in Accounts Payable at June 30, | 205 | 270 |

See Condensed Notes to Condensed Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

INDEX TO CONDENSED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING MATTERS

General

The unaudited condensed consolidated financial statements and footnotes were prepared in accordance with GAAP for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the SEC. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited condensed consolidated interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of our net income, financial position and cash flows for the interim periods. Net income for the three and six months ended June 30, 2010 is not necessarily indicative of results that may be expected for the year ending December 31, 2010. The condensed consolidated financial statements are unaudited and should be read in conjunction with the audited 2009 consolidated financial statements and notes thereto, which are included in our Form 10-K as filed with the SEC on February 26, 2010.

Variable Interest Entities

The accounting guidance for “Variable Interest Entities” is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE’s economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for “Variable Interest Entities.” In determining whether we are the primary beneficiary of a VIE, we consider factors such as equity at risk, the amount of the VIE’s variability we absorb, guarantees of indebtedness, voting rights including kick-out rights, power to direct the VIE and other factors. We believe that significant assumptions and judgments were applied consistently. Also, see the “ASU 2009-17 ‘Consolidations’ ” section of Note 2 for a discussion of the impact of new accounting guidance effective January 1, 2010.

We are the primary beneficiary of Sabine, DCC Fuel LLC, DCC Fuel II LLC, AEP Credit, AEP Texas Central Transition Funding I LLC, AEP Texas Central Transition Funding II LLC and a protected cell of EIS. As of January 1, 2010, we are no longer the primary beneficiary of DHLHC as defined by the new accounting guidance for “Variable Interest Entities.” In addition, we have not provided material financial or other support to Sabine, DCC Fuel, DCC Fuel II, AEP Texas Central Transition Funding I LLC, AEP Texas Central Transition Funding II LLC, our protected cell of EIS and AEP Credit that was not previously contractually required. We hold a significant variable interest in Potomac-Appalachian Transmission Highline, LLC West Virginia Series (West Virginia Series) and DHLHC.

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine’s only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. In addition, SWEPCo determines how much coal will be mined for each year. Based on these facts, management concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo’s total billings from Sabine for the three months ended June 30, 2010 and 2009 were \$30 million and \$25 million, respectively, and for the six months ended June 30, 2010 and 2009 were \$73 million and

\$61 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on our Condensed Consolidated Balance Sheets.

EIS has multiple protected cells. Our subsidiaries participate in one protected cell for approximately ten lines of insurance. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP System is essentially this EIS cell's only participant, but allows certain third parties access to this insurance. Our subsidiaries and any allowed third parties share in the insurance coverage, premiums and risk of loss from claims. Based on our control

and the structure of the protected cell and EIS, management concluded that we are the primary beneficiary of the protected cell and are required to consolidate its assets and liabilities. Our insurance premium payments to the protected cell for the three months ended June 30, 2010 and 2009 were \$254 thousand and \$132 thousand, respectively, and for the six months ended June 30, 2010 and 2009 were \$18 million and \$17 million, respectively. See the tables below for the classification of the protected cell's assets and liabilities on our Condensed Consolidated Balance Sheets. The amount reported as equity is the protected cell's policy holders' surplus.

In September 2009, I&M entered into a nuclear fuel sale and leaseback transaction with DCC Fuel LLC. In April 2010, I&M entered into a nuclear fuel sale and leaseback transaction with DCC Fuel II LLC. DCC Fuel LLC and DCC Fuel II LLC (collectively DCC) were formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. Each entity is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. Payments on the leases are made semi-annually and began in April 2010. Payments on the leases for the three months ended June 30, 2010 were \$22 million and for the six months ended June 30, 2010 were \$22 million. No payments were made to DCC in 2009. The leases were recorded as capital leases on I&M's balance sheet as title to the nuclear fuel transfers to I&M at the end of the 48 and 54 month lease term, respectively. Based on our control of DCC, management concluded that I&M is the primary beneficiary and is required to consolidate DCC. The capital leases are eliminated upon consolidation. See the tables below for the classification of DCC's assets and liabilities on our Condensed Consolidated Balance Sheets.

AEP Credit is a wholly-owned subsidiary of AEP. AEP Credit purchases, without recourse, accounts receivable from certain utility subsidiaries of AEP to reduce working capital requirements. AEP provides up to 20% of AEP Credit's short-term borrowing needs in excess of third party financings. Any third party financing of AEP Credit only has recourse to the receivables sold for such financing. Based on our control of AEP Credit, management has concluded that we are the primary beneficiary and are required to consolidate its assets and liabilities. See the tables below for the classification of AEP Credit's assets and liabilities on our Condensed Consolidated Balance Sheets. See the "ASU 2009-17 'Consolidation' " section of Note 2 for a discussion of the impact of new accounting guidance effective January 1, 2010. Also, see "Sale of Receivables – AEP Credit" section of Note 14 in the 2009 Annual Report for further information.

DHLC is a mining operator who sells 50% of the lignite produced to SWEPCo and 50% to CLECO. SWEPCo and CLECO share the executive board seats and its voting rights equally. Each entity guarantees a 50% share of DHLC's debt. SWEPCo and CLECO equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC, it receives 100% of the management fee. Based on the shared control of DHLC's operations, management concluded as of January 1, 2010 that SWEPCo is no longer the primary beneficiary and is no longer required to consolidate DHLC. SWEPCo's total billings from DHLC for the three months ended June 30, 2010 and 2009 were \$13 million and \$8 million, respectively, and for the six months ended June 30, 2010 and 2009 were \$26 million and \$18 million, respectively. See the tables below for the classification of DHLC's assets and liabilities on our Condensed Consolidated Balance Sheet at December 31, 2009 as well as our investment and maximum exposure as of June 30, 2010. As of January 1, 2010, DHLC is reported as an equity investment in Deferred Charges and Other Noncurrent Assets on our Condensed Consolidated Balance Sheet. Also, see the "ASU 2009-17 'Consolidations' " section of Note 2 for a discussion of the impact of new accounting guidance effective January 1, 2010.

AEP Texas Central Transition Funding I LLC and AEP Texas Central Transition Funding II LLC, wholly-owned subsidiaries of TCC, (collectively Transition Funding) were formed for the sole purpose of issuing and servicing securitization bonds related to Texas restructuring law. Management has concluded that TCC is the primary beneficiary of Transition Funding because TCC has the power to direct the most significant activities of the VIE and TCC's equity interest could potentially be significant. Therefore, TCC is required to consolidate Transition Funding. The securitized bonds totaled \$1.9 billion at June 30, 2010 and are included in current and long-term debt

on the Condensed Consolidated Balance Sheets. Transition Funding has securitized transition assets of \$1.8 billion at June 30, 2010, which are presented separately on the face of the Condensed Consolidated Balance Sheets. The securitized transition assets represent the right to impose and collect Texas true-up costs from customers receiving electric transmission or distribution service from TCC under recovery mechanisms approved by the PUCT. The securitization bonds are payable only from and secured by the securitized transition assets. The bondholders have no recourse to TCC or any other AEP entity. TCC acts as the servicer for Transition Funding's securitized transition asset and remits all related amounts collected from customers to Transition Funding for interest and principal payments on the securitization bonds and related costs.

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The balances below represent the assets and liabilities of the VIEs that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY
COMPANIES

VARIABLE INTEREST ENTITIES

June 30, 2010

(in millions)

| | SWEPCo Sabine | I&M DCC | Protected Cell of EIS | AEP Credit |
|--------------------------------------|------------------|------------|-----------------------------|------------|
| ASSETS | | | | |
| Current Assets | \$ 48 | \$ 76 | \$ 140 | \$ 984 |
| Net Property, Plant and Equipment | 144 | 141 | - | - |
| Other Noncurrent Assets | 34 | 93 | 2 | 10 |
| Total Assets | \$ 226 | \$ 310 | \$ 142 | \$ 994 |
| LIABILITIES AND EQUITY | | | | |
| Current Liabilities | \$ 31 | \$ 63 | \$ 34 | \$ 906 |
| Noncurrent Liabilities | 194 | 247 | 95 | 1 |
| Equity | 1 | - | 13 | 87 |
| Total Liabilities and Equity | \$ 226 | \$ 310 | \$ 142 | \$ 994 |

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY
COMPANIES

VARIABLE INTEREST ENTITIES

December 31, 2009

(in millions)

| | SWEPCo Sabine | SWEPCo DHLC | I&M DCC | Protected Cell of EIS |
|--------------------------------------|------------------|----------------|------------|-----------------------------|
| ASSETS | | | | |
| Current Assets | \$ 51 | \$ 8 | \$ 47 | \$ 130 |
| Net Property, Plant and Equipment | 149 | 44 | 89 | - |
| Other Noncurrent Assets | 35 | 11 | 57 | 2 |
| Total Assets | \$ 235 | \$ 63 | \$ 193 | \$ 132 |
| LIABILITIES AND EQUITY | | | | |
| Current Liabilities | \$ 36 | \$ 17 | \$ 39 | \$ 36 |
| Noncurrent Liabilities | 199 | 38 | 154 | 74 |
| Equity | - | 8 | - | 22 |
| Total Liabilities and Equity | \$ 235 | \$ 63 | \$ 193 | \$ 132 |

Our investment in DHLC was:

| | June 30, 2010 | |
|----------------------------------|------------------|----------|
| | As Reported on | Maximum |
| | the Consolidated | Exposure |
| | Balance Sheet | |
| | (in millions) | |
| Capital Contribution from SWEPCo | \$ 7 | \$ 7 |
| Retained Earnings | 1 | 1 |
| SWEPCo's Guarantee of Debt | - | 48 |
| Total Investment in DHLC | \$ 8 | \$ 56 |

In September 2007, we and Allegheny Energy Inc. (AYE) formed a joint venture by creating Potomac-Appalachian Transmission Highline, LLC (PATH). PATH is a series limited liability company and was created to construct a high-voltage transmission line project in the PJM region. PATH consists of the “Ohio Series,” the “West Virginia Series (PATH-WV),” both owned equally by AYE and AEP, and the “Allegheny Series” which is 100% owned by AYE. Provisions exist within the PATH-WV agreement that make it a VIE. The “Ohio Series” does not include the same provisions that make PATH-WV a VIE. Neither the “Ohio Series” nor “Allegheny Series” are considered VIEs. We are not required to consolidate PATH-WV as we are not the primary beneficiary, although we hold a significant variable interest in PATH-WV. Our equity investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on our Condensed Consolidated Balance Sheets. We and AYE share the returns and losses equally in PATH-WV. Our subsidiaries and AYE’s subsidiaries provide services to the PATH companies through service agreements. At the current time, PATH-WV has no debt outstanding. However, when debt is issued, the debt to equity ratio in each series should be consistent with other regulated utilities. The entities recover costs through regulated rates.

Given the structure of the entity, we may be required to provide future financial support to PATH-WV in the form of a capital call. This would be considered an increase to our investment in the entity. Our maximum exposure to loss is to the extent of our investment. The likelihood of such a loss is remote since the FERC approved PATH-WV’s request for regulatory recovery of cost and a return on the equity invested.

Our investment in PATH-WV was:

| | June 30, 2010 | | December 31, 2009 | |
|-------------------------------|---|---------------------|---|---------------------|
| | As Reported on the Consolidated Balance Sheet | Maximum Exposure | As Reported on the Consolidated Balance Sheet | Maximum Exposure |
| | (in millions) | | | |
| Capital Contribution from AEP | \$ 14 | \$ 14 | \$ 13 | \$ 13 |
| Retained Earnings | 4 | 4 | 3 | 3 |
| Total Investment in PATH-WV | \$ 18 | \$ 18 | \$ 16 | \$ 16 |

Earnings Per Share (EPS)

Basic earnings per common share is calculated by dividing net earnings available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings per common share is calculated by adjusting the weighted average outstanding common shares, assuming conversion of all potentially dilutive stock options and awards.

The following table presents our basic and diluted EPS calculations included on our Condensed Consolidated Statements of Income:

| | | Three Months Ended June 30, | |
|--|--------|--------------------------------------|----------|
| | | 2010 | 2009 |
| | | (in millions, except per share data) | |
| | | \$/share | \$/share |
| Earnings Applicable to AEP Common Shareholders | \$ 136 | | \$ 316 |
| Weighted Average Number of Basic Shares Outstanding | 479.1 | \$ 0.28 | 472.2 |
| Weighted Average Dilutive Effect of: Restricted Stock Units | 0.1 | - | - |
| Weighted Average Number of Diluted Shares Outstanding | 479.2 | \$ 0.28 | 472.2 |
| | | | \$ 0.67 |
| | | Six Months Ended June 30, | |
| | | 2010 | 2009 |
| | | (in millions, except per share data) | |
| | | \$/share | \$/share |
| Earnings Applicable to AEP Common Shareholders | \$ 480 | | \$ 676 |
| Weighted Average Number of Basic Shares Outstanding | 478.7 | \$ 1.00 | 439.7 |
| Weighted Average Dilutive Effect of: Performance Share Units | 0.1 | - | 0.3 |
| Stock Options | 0.1 | - | - |
| Restricted Stock Units | 0.1 | - | - |
| Weighted Average Number of Diluted Shares Outstanding | 479.0 | \$ 1.00 | 440.0 |
| | | | \$ 1.54 |

The assumed conversion of stock options does not affect net earnings for purposes of calculating diluted earnings per share.

Options to purchase 432,366 and 1,123,869 shares of common stock were outstanding at June 30, 2010 and 2009, respectively, but were not included in the computation of diluted earnings per share attributable to AEP common shareholders. Since the options' exercise prices were greater than the average market price of the common shares, the effect would have been antidilutive. AEP's average stock price was \$33.04 per share and its exercise prices for non-dilutive stock options outstanding ranged from \$38.65 to \$49.00 per share.

Supplementary Information

| Related Party Transactions | Three Months Ended June 30, | | Six Months Ended June 30, | |
|--|--------------------------------|------|------------------------------|------|
| | 2010 | 2009 | 2010 | 2009 |
| | (in millions) | | | |
| AEP Consolidated Revenues – Utility Operations: | | | | |
| Ohio Valley Electric Corporation (43.47% owned) (a) | \$ (11) | \$ - | \$ (20) | \$ - |
| AEP Consolidated Revenues – Other Revenues: | | | | |
| Ohio Valley Electric Corporation – Bargaining and Other | | | | |
| Transportation Services (43.47% Owned) | 8 | 7 | 16 | 16 |
| AEP Consolidated Expenses – Purchased Energy for Resale: | | | | |
| Ohio Valley Electric Corporation (43.47% Owned) (b) | 80 | 72 | 157 | 142 |

(a) In January 2010, the AEP Power Pool began purchasing power from OVEC to serve off-system sales through June 2010.

(b) In January 2010, the AEP Power Pool began purchasing power from OVEC to serve retail sales through June 2010. The total amount reported includes \$4 million and \$10 million related to the new agreement for the three and six months ended June 30, 2010, respectively.

Shown below are income statement amounts attributable to AEP common shareholders:

| Amounts Attributable to AEP Common Shareholders | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|-----------------------------|--------|---------------------------|--------|
| | 2010 | 2009 | 2010 | 2009 |
| | (in millions) | | | |
| Income Before Extraordinary Loss | \$ 136 | \$ 321 | \$ 480 | \$ 681 |
| Extraordinary Loss, Net of Tax | - | (5) | - | (5) |
| Net Income | \$ 136 | \$ 316 | \$ 480 | \$ 676 |

Adjustments to Reported Cash Flows

In the Financing Activities section of our Condensed Consolidated Statements of Cash Flows for the six months ended June 30, 2009, we corrected the presentation of borrowings on our lines of credit of \$59 million from Change in Short-term Debt, Net to Borrowings from Revolving Credit Facilities. We also corrected the presentation of repayments on our lines of credit of \$1.8 billion for the six months ended June 30, 2009 to Repayments to Revolving Credit Facilities from Change in Short-term Debt, Net. The correction to present borrowings and repayments on our lines of credit on a gross basis was not material to our financial statements and had no impact on our previously reported net income, changes in shareholders' equity, financial position or net cash flows from financing activities.

Adjustments to Securitized Accounts Receivable Disclosure

In the “Securitized Accounts Receivable – AEP Credit” section of Note 11, we expanded our disclosure to reflect certain prior period amounts related to our securitization agreement that were not previously disclosed. These omissions were not material to our financial statements and had no impact on our previously reported net income, changes in shareholders’ equity, financial position or cash flows.

2. NEW ACCOUNTING PRONOUNCEMENTS AND EXTRAORDINARY ITEM

NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, we review the new accounting literature to determine its relevance, if any, to our business. The following represents a summary of final pronouncements that impact our financial statements.

Pronouncements Adopted During 2010

The following standards were effective during the first six months of 2010. Consequently, their impact is reflected in the financial statements. The following paragraphs discuss their impact.

ASU 2009-16 “Transfers and Servicing” (ASU 2009-16)

In 2009, the FASB issued ASU 2009-16 clarifying when a transfer of a financial asset should be recorded as a sale. The standard defines participating interest to establish specific conditions for a sale of a portion of a financial asset. This standard must be applied to all transfers after the effective date.

We adopted ASU 2009-16 effective January 1, 2010. AEP Credit transfers an interest in receivables it acquires from certain of its affiliates to bank conduits and receives cash. As of December 31, 2009, AEP Credit owed \$656 million to bank conduits related to receivable sales outstanding. Upon adoption of ASU 2009-16, future transactions do not constitute a sale of receivables and are accounted for as financings. Effective January 2010, we record the receivables and related debt on our Condensed Consolidated Balance Sheet.

ASU 2009-17 “Consolidations” (ASU 2009-17)

In 2009, the FASB issued ASU 2009-17 amending the analysis an entity must perform to determine if it has a controlling financial interest in a VIE. In addition to presentation and disclosure guidance, ASU 2009-17 provides that the primary beneficiary of a VIE must have both:

- The power to direct the activities of the VIE that most significantly impact the VIE’s economic performance.
- The obligation to absorb the 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.

We adopted the prospective provisions of ASU 2009-17 effective January 1, 2010 and deconsolidated DHLC. DHLC was deconsolidated due to the shared control between SWEPCo and CLECO. After January 1, 2010, we report DHLC using the equity method of accounting.

This standard increased our disclosure requirements for AEP Credit, a wholly-owned consolidated subsidiary. See “Variable Interest Entities” section of Note 1 for further discussion.

EXTRAORDINARY ITEM

SWEPCo Texas Restructuring

In August 2006, the PUCT adopted a rule extending the delay in implementation of customer choice in SWEPCo’s SPP area of Texas until no sooner than January 1, 2011. In May 2009, the governor of Texas signed a bill related to SWEPCo’s SPP area of Texas that requires continued cost of service regulation until certain stages have been completed and approved by the PUCT such that fair competition is available to all Texas retail customer classes. Based upon the signing of the bill, SWEPCo re-applied “Regulated Operations” accounting guidance for the

generation portion of SWEPCo's Texas retail jurisdiction effective second quarter of 2009. Management believes that a return to competition in the SPP area of Texas will not occur. The reapplication of "Regulated Operations" accounting guidance resulted in an \$8 million (\$5 million, net of tax) extraordinary loss.

3.

RATE MATTERS

As discussed in the 2009 Annual Report, our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within our 2009 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2010 and updates the 2009 Annual Report.

Regulatory Assets Not Yet Being Recovered

| | June 30, 2010 | December 31, 2009 |
|--|------------------|----------------------|
| | (in millions) | |
| Noncurrent Regulatory Assets (excluding fuel) | | |
| Regulatory assets not yet being recovered pending future proceedings | | |
| to determine the recovery method and timing: | | |
| Regulatory Assets Currently Earning a Return | | |
| Customer Choice Deferrals - CSPCo, OPCo | \$ 58 | \$ 57 |
| Storm Related Costs - CSPCo, OPCo, TCC | 50 | 49 |
| Line Extension Carrying Costs - CSPCo, OPCo | 49 | 43 |
| Acquisition of Monongahela Power - CSPCo | 11 | 10 |
| Regulatory Assets Currently Not Earning a Return | | |
| Mountaineer Carbon Capture and Storage Project - APCo | 58 | 111 |
| Environmental Rate Adjustment Clause - APCo | 43 | 25 |
| Storm Related Costs - APCo, PSO | 41 | - |
| Transmission Rate Adjustment Clause - APCo | 21 | 26 |
| Special Rate Mechanism for Century Aluminum - APCo | 13 | 12 |
| Deferred Wind Power Costs - APCo | 12 | 5 |
| Storm Related Costs - KPCo | - (a) | 24 |
| Peak Demand Reduction/Energy Efficiency - CSPCo, OPCo | - (a) | 8 |
| Total Regulatory Assets Not Yet Being Recovered | \$ 356 | \$ 370 |

(a) Recovery of regulatory asset was granted during 2010.

CSPCo and OPCo Rate Matters

Ohio Electric Security Plan Filings

The PUCO issued an order in March 2009 that modified and approved CSPCo's and OPCo's ESPs which established rates at the start of the April 2009 billing cycle. The ESPs are in effect through 2011. The order also limits annual rate increases for CSPCo to 7% in 2009, 6% in 2010 and 6% in 2011 and for OPCo to 8% in 2009, 7% in 2010 and 8% in 2011. Some rate components and increases are exempt from these limitations. CSPCo and OPCo collected the 2009 annualized revenue increase over the last nine months of 2009.

The order provides a FAC for the three-year period of the ESP. The FAC increase will be phased in to avoid having the resultant rate increases exceed the ordered annual caps described above. The FAC increase is subject to quarterly true-ups, annual accounting audits and prudence reviews. See the “2009 Fuel Adjustment Clause Audit” section below. The order allows CSPCo and OPCo to defer any unrecovered FAC costs resulting from the annual caps and to accrue associated carrying charges at CSPCo’s and OPCo’s weighted average cost of capital. Any deferred FAC regulatory asset balance at the end of the three-year ESP period will be recovered through a non-bypassable surcharge over the period 2012 through 2018. Management expects to recover the CSPCo FAC deferral during 2010. That recovery will include deferrals associated with the Ormet interim arrangement and is subject to the PUCO’s ultimate decision regarding the Ormet interim arrangement deferrals plus related carrying charges. See the “Ormet Interim Arrangement” section below. The FAC deferrals as of June 30, 2010 were \$5 million and \$388 million for CSPCo and OPCo, respectively, excluding \$1 million and \$18 million, respectively, of unrecognized equity carrying costs.

Discussed below are the outstanding uncertainties related to the ESP order:

The Ohio Consumers' Counsel filed a notice of appeal with the Supreme Court of Ohio raising several issues including alleged retroactive ratemaking, recovery of carrying charges on certain environmental investments, Provider of Last Resort (POLR) charges and the decision not to offset rates by off-system sales margins. A decision from the Supreme Court of Ohio is pending.

In November 2009, the Industrial Energy Users-Ohio group filed a notice of appeal with the Supreme Court of Ohio challenging components of the ESP order including the POLR charge, the distribution riders for gridSMARTSM and enhanced reliability, the PUCO's conclusion and supporting evaluation that the modified ESPs are more favorable than the expected results of a market rate offer, the unbundling of the fuel and non-fuel generation rate components, the scope and design of the fuel adjustment clause and the approval of the plan after the 150-day statutory deadline. A decision from the Supreme Court of Ohio is pending.

In April 2010, the Industrial Energy Users-Ohio group filed an additional notice of appeal with the Supreme Court of Ohio challenging alleged retroactive ratemaking, CSPCo's and OPCo's abilities to collect through the FAC amounts deferred under the Ormet interim arrangement and the approval of the plan after the 150-day statutory deadline. A decision from the Supreme Court of Ohio is pending.

In 2009, the PUCO convened a workshop to determine the methodology for the Significantly Excessive Earnings Test (SEET). Ohio law requires that the PUCO determine, following the end of each year of the ESP, if rate adjustments included in the ESP resulted in significantly excessive earnings. If the rate adjustments, in the aggregate, result in significantly excessive earnings, the excess amount could be returned to customers. The PUCO heard arguments related to various SEET issues including the treatment of the FAC deferrals. Management believes that CSPCo and OPCo should not be required to refund unrecovered FAC regulatory assets until they are collected, even assuming there are significantly excessive earnings in that year. In June 2010, the PUCO issued an order resolving some of the SEET issues. The PUCO determined that the earnings of CSPCo and OPCo shall be calculated on an individual company basis and not on a combined CSPCo/OPCo basis. The PUCO ruled that many issues including the treatment of deferrals and off-system sales should be determined on a case-by-case basis. The PUCO's decision on the SEET methodology is not expected to be finalized until after the SEET filings are made by CSPCo and OPCo related to 2009 earnings and the PUCO issues an order thereon. CSPCo and OPCo will file their significantly excessive earnings tests with the PUCO by their September 2010 deadlines. CSPCo and OPCo are unable to determine whether they will be required to return any of their ESP revenues to customers.

Management is unable to predict the outcome of the various ongoing ESP proceedings and litigation discussed above. If these proceedings result in adverse rulings, it could reduce future net income and cash flows and impact financial condition.

2009 Fuel Adjustment Clause Audit

As required under the ESP orders, the PUCO selected an outside consultant to conduct the audit of the FAC for the period of January 2009 through December 2009. In May 2010, the outside consultant provided their confidential audit report of the FAC audit to the PUCO. The audit report included a recommendation that the PUCO should review whether any proceeds from a 2008 coal contract settlement agreement which totaled \$72 million should reduce OPCo's FAC under-recovery balance. Of the total proceeds, approximately \$58 million was recognized as a reduction to fuel expense prior to 2009 and \$14 million will reduce fuel expense in 2009 and 2010. If the PUCO orders any portion of the \$58 million previously recognized gains be used to reduce the current year FAC deferral, it would reduce future net income and cash flows and impact financial condition.

Ormet Interim Arrangement

CSPCo, OPCo and Ormet, a large aluminum company, filed an application with the PUCO for approval of an interim arrangement governing the provision of generation service to Ormet. This interim arrangement was approved by the PUCO and was effective from January 2009 through September 2009. In March 2009, the PUCO approved a FAC in the ESP filings. The approval of the FAC, together with the PUCO approval of the interim

arrangement, provided the basis to record regulatory assets for the difference between the approved market price and the rate paid by Ormet. Through September 2009, the last month of the interim arrangement, CSPCo and OPCo had \$30 million and \$34 million, respectively, of deferred FAC related to the interim arrangement including recognized carrying charges but excluding \$1 million and \$1 million, respectively, of unrecognized equity carrying costs. In November 2009, CSPCo and OPCo requested that the PUCO approve recovery of the deferrals under the interim agreement plus a weighted average cost of capital carrying charge. The interim arrangement deferrals are included in CSPCo's and OPCo's FAC phase-in deferral balances. See "Ohio Electric Security Plan Filings" section above. In the ESP proceeding, intervenors requested that CSPCo and OPCo be required to refund the Ormet-related regulatory assets and requested that the PUCO prevent CSPCo and OPCo from collecting the Ormet-related revenues in the future. The PUCO did not take any action on this request in the ESP proceeding. The intervenors raised the issue again in response to CSPCo's and OPCo's November 2009 filing to approve recovery of the deferrals under the interim agreement. If CSPCo and OPCo are not ultimately permitted to fully recover their requested deferrals under the interim arrangement, it would reduce future net income and cash flows and impact financial condition.

Economic Development Rider

In April 2010, the Industrial Energy Users-Ohio filed a notice of appeal of the 2009 PUCO-approved Economic Development Rider (EDR) with the Supreme Court of Ohio. The EDR collects from ratepayers the difference between the standard tariff and lower contract billings to qualifying industrial customers, subject to PUCO approval. The Industrial Energy Users-Ohio raised several issues including claims that (a) the PUCO lost jurisdiction over CSPCo's and OPCo's ESP proceedings and related proceedings when the PUCO failed to issue ESP orders within the 150-day statutory deadline, (b) the EDR should not be exempt from the ESP annual rate limitations and (c) CSPCo and OPCo should not be allowed to apply a weighted average long-term debt carrying cost on deferred EDR regulatory assets.

In June 2010, Industrial Energy Users-Ohio filed a notice of appeal of the 2010 PUCO-approved Economic Development Rider (EDR) with the Supreme Court of Ohio. The Industrial Energy Users-Ohio raised the same issues as noted in the 2009 EDR appeal plus a claim that CSPCo and OPCo should not be able to take the benefits of the higher ESP rates while simultaneously challenging the ESP Orders.

As of June 30, 2010, CSPCo and OPCo have incurred \$32 million and \$23 million, respectively, in EDR costs including carrying costs. Of these costs, CSPCo and OPCo have collected \$16 million and \$12 million, respectively, through the EDR, which CSPCo and OPCo began collecting in January 2010. The remaining \$16 million and \$11 million for CSPCo and OPCo, respectively, are recorded as EDR regulatory assets. If CSPCo and OPCo are not ultimately permitted to recover their deferrals or are required to refund revenue collected, it would reduce future net income and cash flows and impact financial condition.

Environmental Investment Carrying Cost Rider

In February 2010, CSPCo and OPCo filed an application with the PUCO to establish an Environmental Investment Carrying Cost Rider to recover carrying costs for 2009 through 2011 related to environmental investments made in 2009. CSPCo's and OPCo's proposed initial rider would recover 2009 carrying costs of \$29 million and \$37 million, respectively, through December 2011. In July 2010, CSPCo and OPCo filed an updated position to its application which reduced its original rider application amount to recover \$27 million and \$35 million, respectively, through December 2011. If approved, the implementation of the rider will likely not impact cash flows, but will increase the ESP phase-in plan deferrals associated with the FAC since this rider is subject to the rate increase caps authorized by the PUCO in the ESP proceedings.

Ohio IGCC Plant

In March 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs of building and operating an IGCC power plant. Through June 30, 2010, CSPCo and OPCo have each collected \$12 million in pre-construction costs authorized in a June 2006 PUCO order and each incurred \$11 million in pre-construction costs. As a result, CSPCo and OPCo each established a net regulatory liability of approximately \$1 million. The order also provided that if CSPCo and OPCo have not commenced a continuous course of construction

of the proposed IGCC plant before June 2011, all pre-construction costs that may be utilized in projects at other sites must be refunded to Ohio ratepayers with interest. Intervenor has filed motions with the PUCO requesting all pre-construction costs be refunded to Ohio ratepayers with interest.

CSPCo and OPCo will not start construction of an IGCC plant until existing statutory barriers are addressed and sufficient assurance of regulatory cost recovery exists. Management cannot predict the outcome of any cost recovery litigation concerning the Ohio IGCC plant or what effect, if any, such litigation would have on future net income and cash flows. However, if CSPCo and OPCo were required to refund all or some of the pre-construction costs collected and the costs incurred were not recoverable in another jurisdiction, it would reduce future net income and cash flows and impact financial condition.

Ohio Energy Efficiency & Demand Response Program Rider

In November 2009, CSPCo and OPCo filed an application with the PUCO to implement energy efficiency and demand response programs as part of Senate Bill 221, which requires investor-owned utilities to create programs to help customers conserve and reduce demand for electricity. Simultaneous with the filing, a stipulation agreement was filed with the PUCO agreeing to terms consistent with the filed application. In May 2010, the PUCO issued an order adopting the stipulation, with minor modification, and authorized CSPCo and OPCo to implement a new rider rate effective with the first billing cycle in June 2010. The rider rates are estimated to increase CSPCo's and OPCo's revenues by \$81 million and \$86 million, respectively, over the period from June 2010 through December 2011. CSPCo's and OPCo's revenue increases include \$79 million and \$83 million, respectively, for program costs and \$2 million and \$3 million, respectively, for net lost distribution revenues and shared savings.

SWEPCo Rate Matters

Turk Plant

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which is expected to be in service in 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and will operate the completed facility. The Turk Plant is currently estimated to cost \$1.7 billion, excluding AFUDC, plus an additional \$131 million for transmission, excluding AFUDC. SWEPCo's share is currently estimated to cost \$1.3 billion, excluding AFUDC, plus an additional \$131 million for transmission, excluding AFUDC. As of June 30, 2010, excluding costs attributable to its joint owners, SWEPCo has capitalized approximately \$855 million of expenditures (including AFUDC and capitalized interest of \$106 million and related transmission costs of \$46 million). As of June 30, 2010, the joint owners and SWEPCo have contractual construction commitments of approximately \$425 million (including related transmission costs of \$7 million). SWEPCo's share of the contractual construction commitments is \$312 million. If the plant is cancelled, the joint owners and SWEPCo would incur contractual construction cancellation fees, based on construction status as of June 30, 2010, of approximately \$121 million (including related transmission cancellation fees of \$1 million). SWEPCo's share of the contractual construction cancellation fees would be approximately \$89 million.

Discussed below are the outstanding uncertainties related to the Turk Plant:

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the 88 MW SWEPCo Arkansas share of the Turk Plant. Following an appeal by certain intervenors, the Arkansas Supreme Court issued a decision that reversed the APSC's grant of the CECPN. The Arkansas Supreme Court ultimately concluded that the APSC erred in determining the need for additional power supply resources in a proceeding separate from the proceeding in which the APSC granted the CECPN. However, the Arkansas Supreme Court approved the APSC's procedure of granting CECPNs for transmission facilities in dockets separate from the Turk Plant CECPN proceeding. In June 2010, the Arkansas

Supreme Court denied motions for rehearing filed by the APSC and SWEPCo. Therefore, SWEPCo filed a notice with the APSC of its intent to proceed with construction of the Turk Plant but that SWEPCo no longer intends to pursue a CECPN to seek recovery of the originally approved 88MW portion of Turk Plant costs in Arkansas retail rates. In June 2010, the APSC issued an order which reversed and set aside the previously granted CECPN.

In July 2010, the Hempstead County Hunting Club filed a complaint with the Federal District Court for the Western District of Arkansas against SWEPCo, the U.S. Army Corps of Engineers, the U.S. Department of Interior and the U.S. Fish and Wildlife Service seeking an injunction to stop construction of the Turk Plant asserting claims of violations of federal and state laws.

The PUCT issued an order approving a Certificate of Convenience and Necessity (CCN) for the Turk Plant with the following conditions: (a) a cap on the recovery of jurisdictional capital costs for the Turk Plant based on the previously estimated \$1.522 billion projected construction cost, excluding AFUDC and related transmission costs, (b) a cap on recovery of annual CO2 emission costs at \$28 per ton through the year 2030 and (c) a requirement to hold Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers. SWEPCo appealed the PUCT's order contending the two cost cap restrictions are unlawful. The Texas Industrial Energy Consumers filed an appeal contending that the PUCT's grant of a conditional CCN for the Turk Plant was unnecessary to serve retail customers. In February 2010, the Texas District Court affirmed the PUCT's order in all respects. In March 2010, SWEPCo and the Texas Industrial Energy Consumers appealed this decision to the Texas Court of Appeals.

The LPSC approved SWEPCo's application to construct the Turk Plant. The Sierra Club petitioned the LPSC to begin an investigation into the construction of the Turk Plant which was rejected by the LPSC in November 2009. In December 2009, the Sierra Club refiled its petition as a stand alone complaint proceeding. In February 2010, SWEPCo filed a motion to dismiss and denied the allegations in the complaint.

In November 2008, SWEPCo received its required air permit approval from the Arkansas Department of Environmental Quality and commenced construction at the site. The Arkansas Pollution Control and Ecology Commission (APCEC) upheld the air permit. In February 2010, the parties who unsuccessfully appealed the air permit to the APCEC filed a notice of appeal with the Circuit Court of Hempstead County, Arkansas.

The wetlands permit was issued by the U.S. Army Corps of Engineers in December 2009. In February 2010, the Sierra Club, the Audubon Society and others filed a complaint in the Federal District Court for the Western District of Arkansas against the U.S. Army Corps of Engineers challenging the process used and the terms of the permit issued to SWEPCo authorizing certain wetland and stream impacts. In May 2010, parties filed with the Federal District Court for the Western District of Arkansas for a preliminary injunction to halt construction and for a temporary restraining order.

In January 2009, SWEPCO was granted CECPNs by the APSC to build three transmission lines and facilities authorized by the SPP and needed to transmit power from the Turk Plant. Intervenor appeals the CECPN decisions in April 2009 to the Arkansas Court of Appeals. In July 2010, the Hempstead County Hunting Club and other appellants filed with the Arkansas Court of Appeals emergency motions to stay the transmission CECPNs to prohibit SWEPCo from taking ownership of private property and undertaking construction of the transmission lines. In July 2010, the Arkansas Court of Appeals issued a decision remanding all transmission line CECPN appeals to the APSC. As a result, a stay was not ordered and construction continues on the affected transmission lines.

Management expects that SWEPCo will ultimately be able to complete construction of the Turk Plant and related transmission facilities and place those facilities in service. However, if SWEPCo is unable to complete the Turk Plant construction, including the related transmission facilities, and place the Turk Plant in service or if SWEPCo cannot recover all of its investment in and expenses related to the Turk Plant, it would materially reduce future net income and cash flows and materially impact financial condition.

Stall Unit

SWEPCo constructed the Stall Unit, an intermediate load 500 MW natural gas-fired combustion turbine combined cycle generating unit, at its existing Arsenal Hill Plant located in Shreveport, Louisiana. The LPSC and the APSC issued orders capping SWEPCo's Stall Unit construction costs at \$445 million including AFUDC and excluding related transmission costs. The Stall Unit was placed in service in June 2010. As of June 30, 2010, the Stall Unit cost \$422 million, including \$49 million of AFUDC. Management does not expect the final costs of the Stall Unit to exceed the ordered cap.

2009 Texas Base Rate Filing

In August 2009, SWEPCo filed a rate case with the PUCT to increase its base rates by approximately \$75 million annually including a return on equity of 11.5%. The filing included requests for financing cost riders of \$32 million related to construction of the Stall Unit and Turk Plant, a vegetation management rider of \$16 million and other requested increases of \$27 million. In April 2010, a settlement agreement was approved by the PUCT to increase SWEPCo's base rates by approximately \$15 million annually, effective May 2010, including a return on equity of 10.33%, which consists of \$5 million related to construction of the Stall Unit and \$10 million in other increases. In addition, the settlement agreement will decrease annual depreciation expense by \$17 million and allows SWEPCo a \$10 million one-year surcharge rider to recover additional vegetation management costs that SWEPCo must spend within two years.

Texas Fuel Reconciliation

In May 2010, various intervenors, including the PUCT staff, filed testimony recommending disallowances ranging from \$3 million to \$30 million in SWEPCo's \$755 million fuel and purchase power costs reconciliation for the period January 2006 through March 2009. In July 2010, Cities Advocating Reasonable Deregulation filed testimony regarding the 2007 transfer of ERCOT trading contracts to AEP Energy Partners. Included in this testimony were unquantified refund recommendations relating to re-pricing of contract transactions. Management is unable to predict the outcome of this reconciliation. If the PUCT disallows any portion of SWEPCo's fuel and purchase power costs, it could reduce future net income and cash flows and possibly impact financial condition.

TCC and TNC Rate Matters

TEXAS RESTRUCTURING

Texas Restructuring Appeals

Pursuant to PUCT restructuring orders, TCC securitized net recoverable stranded generation costs of \$2.5 billion and is recovering the principal and interest on the securitization bonds through the end of 2020. TCC also refunded other net true-up regulatory liabilities of \$375 million during the period October 2006 through June 2008 via a CTC credit rate rider under PUCT restructuring orders. TCC and intervenors appealed the PUCT's true-up related orders. After rulings from the Texas District Court and the Texas Court of Appeals, TCC, the PUCT and intervenors filed petitions for review with the Texas Supreme Court. Review is discretionary and the Texas Supreme Court has not yet determined if it will grant review. The Texas Supreme Court requested a full briefing which has concluded. The following represent issues where either the Texas District Court or the Texas Court of Appeals recommended the PUCT decision be modified:

- The Texas District Court judge determined that the PUCT erred by applying an invalid rule to determine the carrying cost rate for the true-up of stranded costs. The Texas Court of Appeals reversed the District Court's unfavorable decision.
- The Texas District Court judge determined that the PUCT improperly reduced TCC's net stranded plant costs for commercial unreasonableness. This favorable decision was affirmed by the Texas Court of Appeals.
- The Texas Court of Appeals determined that the PUCT erred by not reducing stranded costs by the "excess earnings" that had already been refunded to affiliated REPs. This decision could be unfavorable unless the PUCT allows TCC to recover the refunds previously made to the REPs. See the "TCC Excess Earnings" section below.

Management cannot predict the outcome of the pending court proceedings and the PUCT remand decisions. If TCC ultimately succeeds in its appeals, it could have a favorable effect on future net income, cash flows and possibly financial condition. If intervenors succeed in their appeals, it could reduce future net income and cash flows and possibly impact financial condition.

TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes

In 2006, the PUCT reduced recovery of the amount securitized by \$103 million of tax benefits and associated carrying costs related to TCC's generation assets. In 2006, TCC obtained a private letter ruling from the IRS which confirmed that such reduction was an IRS normalization violation. In order to avoid a normalization violation, the PUCT agreed to allow TCC to defer refunding the tax benefits of \$103 million plus interest through the CTC refund period pending resolution of the normalization issue. In 2008, the IRS issued final regulations, which supported the IRS' private letter ruling which would make the refunding of or the reduction of the amount securitized by such tax benefits a normalization violation. After the IRS issued its final regulations, at the request of the PUCT, the Texas Court of Appeals remanded the tax normalization issue to the PUCT for the consideration of additional evidence including the IRS regulations. TCC is not accruing interest on the \$103 million because it is not probable that the PUCT will order TCC to violate the normalization provision of the Internal Revenue Code. If interest were accrued, management estimates interest expense would have been approximately \$17 million higher for the period July 2008 through June 2010.

Management believes that the PUCT will ultimately allow TCC to retain the deferred amounts, which would have a favorable effect on future net income and cash flows. Although unexpected, if the PUCT fails to issue a favorable order and orders TCC to return the tax benefits to customers, the resulting normalization violation could result in TCC's repayment to the IRS of Accumulated Deferred Investment Tax Credits (ADITC) on all property, including transmission and distribution property. This amount approximates \$102 million as of June 30, 2010. It could also lead to a loss of TCC's right to claim accelerated tax depreciation in future tax returns. If TCC is required to repay its ADITC to the IRS and is also required to refund ADITC plus unaccrued interest to customers, it would reduce future net income and cash flows and impact financial condition.

TCC Excess Earnings

In 2005, a Texas appellate court issued a decision finding that a PUCT order requiring TCC to refund to the REPs excess earnings prior to and outside of the true-up process was unlawful under the Texas Restructuring Legislation. From 2002 to 2005, TCC refunded \$55 million of excess earnings, including interest, under the overturned PUCT order. On remand, the PUCT must determine how to implement the Court of Appeals decision given that the unauthorized refunds were made to the REPs in lieu of reducing stranded costs in the true-up proceeding.

Certain parties have taken positions that, if adopted, could result in TCC being required to refund excess earnings and interest through the true-up process without receiving a refund from the REPs. If this were to occur, it would reduce future net income and cash flows and impact financial condition. Management cannot predict the outcome of the excess earnings remand.

OTHER TEXAS RATE MATTERS

Texas Base Rate Appeal

TCC filed a base rate case in 2006 seeking to increase base rates. The PUCT issued an order in 2007 which increased TCC's base rates by \$20 million, eliminated a merger credit rider of \$20 million and reduced depreciation rates by \$7 million. The PUCT decision was appealed by TCC and various intervenors. On appeal, the Texas District Court affirmed the PUCT in most respects. Various intervenors appealed that decision. In June 2010, the Texas Court of Appeals affirmed the Texas District Court's decision.

ETT 2007 Formation Appeal

ETT is a joint venture between AEP Utilities, Inc. and MidAmerican Energy Holdings Company Texas Transco, LLC. TCC and TNC have sold transmission assets both in service and under construction to ETT. The PUCT approved ETT's initial rates, a request for a transfer of in-service assets and CWIP and a certificate of convenience and necessity (CCN) to operate as a stand alone transmission utility in ERCOT. ETT was allowed a 9.96% return on equity. Intervenors appealed the PUCT's decision. In March 2010, the Texas Court of Appeals affirmed the PUCT's decision in all material respects. In April 2010, intervenors filed for rehearing at the Texas Court of Appeals which was denied in May 2010.

In a separate development, the Texas governor signed a new law that clarifies the PUCT's authority to grant CCNs to transmission only utilities such as ETT. ETT filed an application with the PUCT for a CCN under the new law. In March 2010, the PUCT approved the application for a CCN under the new law.

APCo and WPCo Rate Matters

2009 Virginia Base Rate Case

In July 2009, APCo filed a generation and distribution base rate increase with the Virginia SCC of \$154 million annually based on a 13.35% return on common equity. Interim rates, subject to refund, became effective in December 2009 but were discontinued in February 2010 when newly enacted Virginia legislation suspended the collection of interim rates. In July 2010, the Virginia SCC issued an order approving a \$62 million increase based on a 10.53% return on equity. The order denied recovery of the Virginia share of the Mountaineer Carbon Capture and Storage Project, which resulted in a pretax write-off of \$54 million in the second quarter of 2010. See "Mountaineer Carbon Capture and Storage Project" section below. In addition, the order allowed the deferral in the second quarter of 2010 of approximately \$25 million of incremental storm expense incurred in 2009. In July 2010, APCo filed with the Virginia SCC a petition for reconsideration of the order as it relates to the Mountaineer Carbon Capture and Storage Project.

2010 West Virginia Base Rate Case

In May 2010, APCo and WPCo filed a request with the WVPSC to increase annual base rates by \$156 million based on an 11.75% return on common equity to be effective March 2011. Hearings are scheduled for December 2010. A decision from the WVPSC is expected in March 2011.

Mountaineer Carbon Capture and Storage Project

APCo and ALSTOM Power, Inc., an unrelated third party, jointly constructed a CO₂ capture validation facility, which was placed into service in September 2009. APCo also constructed and owns the necessary facilities to store the CO₂. In October 2009, APCo started injecting CO₂ into the underground storage facilities. The injection of CO₂ required the recording of an asset retirement obligation and an offsetting regulatory asset. Through June 30, 2010, APCo has recorded a noncurrent regulatory asset of \$58 million consisting of \$38 million in project costs and \$20 million in asset retirement costs.

In APCo's July 2009 Virginia base rate filing, APCo requested recovery of and a return on its estimated increased Virginia jurisdictional share of its project costs and recovery of the related asset retirement obligation regulatory asset amortization and accretion. In July 2010, the Virginia SCC issued a base rate order that denied recovery of the Virginia share of the Mountaineer Carbon Capture and Storage Project costs, which resulted in a write-off of approximately \$54 million in the second quarter of 2010. In response to the order, APCo filed with the Virginia SCC a petition for reconsideration of the order as it relates to the Mountaineer Carbon Capture and Storage Project. See "2009 Virginia Base Rate Case" section above.

In APCo's May 2010 West Virginia base rate filing, APCo requested recovery of and a return on its estimated increased West Virginia jurisdictional share of its project costs and recovery of the related asset retirement obligation regulatory asset amortization and accretion. If APCo cannot recover its remaining investment in and expenses related to the Mountaineer Carbon Capture and Storage project, it would reduce future net income and cash flows and impact financial condition.

APCo's Filings for an IGCC Plant

APCo filed a petition with the WVPSC requesting approval of a Certificate of Public Convenience and Necessity (CPCN) to construct a 629 MW IGCC power plant in Mason County, West Virginia. APCo also requested the Virginia SCC and the WVPSC to approve a surcharge rate mechanism to provide for the timely recovery of pre-construction costs and the ongoing financing costs of the project during the construction period, as well as the capital costs, operating costs and a return on equity once the facility is placed into commercial operation. The WVPSC granted APCo the CPCN and approved the requested cost recovery. Various intervenors filed petitions with the WVPSC to reconsider the order.

In 2008, the Virginia SCC issued an order denying APCo's request for a surcharge rate mechanism based upon its finding that the estimated cost of the plant was uncertain and may escalate. The Virginia SCC also expressed concerns that the estimated costs did not include a retrofitting of carbon capture and sequestration facilities. During 2009, based on an unfavorable order received in Virginia, the WVPSC removed the IGCC case as an active case from its docket and indicated that the conditional CPCN granted in 2008 must be reconsidered if and when APCo proceeds forward with the IGCC plant.

Through June 30, 2010, APCo deferred for future recovery pre-construction IGCC costs of approximately \$9 million applicable to its West Virginia jurisdiction, approximately \$2 million applicable to its FERC jurisdiction and approximately \$9 million applicable to its Virginia jurisdiction.

APCo will not start construction of the IGCC plant until sufficient assurance of full cost recovery exists in Virginia and in West Virginia. If the plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs which, if not recoverable, would reduce future net income and cash flows and impact financial condition.

APCo's and WPCo's 2009 Expanded Net Energy Charge (ENEC) Filing

In September 2009, the WVPSC issued an order approving APCo's and WPCo's March 2009 ENEC request. The approved order provided for recovery of an under-recovered balance plus a projected increase in ENEC costs over a four-year phase-in period with an overall increase of \$355 million and a first-year increase of \$124 million, effective October 2009. The WVPSC also approved a fixed annual carrying cost rate of 4%, effective October 2009, to be applied to the incremental deferred regulatory asset balance that will result from the phase-in plan and lowered annual coal cost projections by \$27 million. As of June 30, 2010, APCo's ENEC under-recovery balance was \$358 million, including carrying costs, which is included in noncurrent regulatory assets.

In June 2010, a settlement agreement for \$96 million, including \$10 million of construction surcharges, was filed with the WVPSC related to APCo's and WPCo's second year ENEC increase. The settlement agreement provided for recovery of the amounts related to the renegotiated coal contracts and allows APCo to accrue weighted average cost of capital carrying costs on the excess under-recovery balance due to the ENEC phase-in as adjusted for the impacts of Accumulated Deferred Income Taxes. In June 2010, the WVPSC approved the settlement agreement which made rates effective in July 2010.

PSO Rate Matters

PSO Fuel and Purchased Power

2006 and Prior Fuel and Purchased Power

The OCC filed a complaint with the FERC related to the allocation of off-system sales margins (OSS) among the AEP operating companies in accordance with a FERC-approved allocation agreement. The FERC issued an adverse ruling in 2008. As a result, PSO recorded a regulatory liability in 2008 to return reallocated OSS to customers. Starting in March 2009, PSO refunded the additional reallocated OSS to its customers through February 2010.

A reallocation of purchased power costs among AEP West companies for periods prior to 2002 resulted in an under-recovery of \$42 million of PSO fuel costs. PSO recovered the \$42 million by offsetting it against an existing fuel over-recovery during the period June 2007 through May 2008. The Oklahoma Industrial Energy Consumers (OIEC) has contended that PSO should not have collected the \$42 million without specific OCC approval. As such, the OIEC contends that the OCC should require PSO to refund the \$42 million it collected through its fuel clause. The OCC has heard the OIEC appeal and a decision is pending. In March 2010, PSO filed motions to

advance this proceeding since the FERC has ruled on the allocation of off-system sales margins proceeding and PSO has refunded the additional margins to its retail customers. If the OCC were to order PSO to refund all or a part of the \$42 million, it would reduce future net income and cash flows and impact financial condition.

2008 Fuel and Purchased Power

In July 2009, the OCC initiated a proceeding to review PSO's fuel and purchased power adjustment clause for the calendar year 2008 and also initiated a prudence review of the related costs. In March 2010, the Oklahoma Attorney General and the OIEC recommended the fuel clause adjustment rider be amended so that the shareholder's portion of off-system sales margins decrease from 25% to 10%. The OIEC also recommended that the OCC conduct a comprehensive review of all affiliate transactions during 2007 and 2008. In July 2010, additional testimony regarding the 2007 transfer of ERCOT trading contracts to AEP Energy Partners was filed. Included in this testimony were unquantified refund recommendations relating to re-pricing of contract transactions. If the OCC were to issue an unfavorable decision, it could reduce future net income and cash flows and impact financial condition.

2008 Oklahoma Base Rate Appeal

In January 2009, the OCC issued a final order approving an \$81 million increase in PSO's non-fuel base revenues based on a 10.5% return on equity. The new rates reflecting the final order were implemented with the first billing cycle of February 2009. PSO and intervenors filed appeals with the Oklahoma Supreme Court raising various issues. The Oklahoma Supreme Court assigned the case to the Court of Civil Appeals. In June 2010, the Court of Civil Appeals affirmed the OCC's decision. No parties sought rehearing or appeal. As a result, this case has concluded.

2010 Oklahoma Base Rate Case

In July 2010, PSO filed a request with the OCC to increase annual base rates by \$82 million, including \$30 million that is currently being recovered through a rider. The requested increase includes a \$24 million increase in depreciation and an 11.5% return on common equity. PSO requested that new rates become effective no later than July 2011. A procedural schedule has not been established.

I&M Rate Matters

Indiana Fuel Clause Filing (Cook Plant Unit 1 Fire and Shutdown)

I&M filed applications with the IURC to increase its fuel adjustment charge by approximately \$53 million for the period of April 2009 through September 2009. The filings sought increases for previously under-recovered fuel clause expenses.

As fully discussed in the "Cook Plant Unit 1 Fire and Shutdown" section of Note 4, Cook Unit 1 was shut down in September 2008 due to significant turbine damage and a small fire on the electric generator. Unit 1 was placed back into service in December 2009 at slightly reduced power. The unit outage resulted in increased replacement power fuel costs. The filing only requested the cost of replacement power through mid-December 2008, the date when I&M began receiving accidental outage insurance proceeds. I&M committed to absorb the remaining costs of replacement power through the date the unit returned to service, which occurred in December 2009.

I&M reached an agreement with intervenors, which was approved by the IURC in March 2009, to collect its existing prior period under-recovery regulatory asset deferral balance over twelve months instead of over six months as initially proposed. Under the agreement, the fuel factors were placed into effect, subject to refund, and a subdocket was established to consider issues relating to the Unit 1 shutdown including the treatment of the accidental outage insurance proceeds. Hearings are scheduled to be held in December 2010.

Management believes that I&M is entitled to retain the accidental outage insurance proceeds since it made customers whole regarding the replacement power costs. If any fuel clause revenues or accidental outage insurance proceeds

have to be refunded, it would reduce future net income and cash flows and impact financial condition.

Michigan 2009 Power Supply Cost Recovery (PSCR) Reconciliation (Cook Plant Unit 1 Fire and Shutdown)

In March 2010, I&M filed its 2009 PSCR reconciliation with the MPSC. The filing included an adjustment to exclude from the PSCR the incremental fuel cost of replacement power due to the Cook Plant Unit 1 outage from mid-December 2008 through December 2009, the period during which I&M received and recognized the accidental outage insurance proceeds. Management believes that I&M is entitled to retain the accidental outage insurance proceeds since it made customers whole regarding the replacement power costs. If any fuel clause revenues or accidental outage insurance proceeds have to be refunded, it would reduce future net income and cash flows and impact financial condition. See the "Cook Plant Unit 1 Fire and Shutdown" section of Note 4.

Michigan Base Rate Filing

In January 2010, I&M filed with the MPSC a request for a \$63 million increase in annual base rates based on an 11.75% return on common equity. In the August 2010 billing cycle, I&M, with the MPSC authorization, will implement a \$44 million interim rate increase, subject to refund with interest. The interim increase excluded new trackers and regulatory assets for which I&M was not currently incurring expenses. In July 2010, the MPSC staff filed testimony which recommended a \$34 million annual increase in base rates based on a 10.35% return on common equity plus separate recovery of approximately \$7 million of customer choice implementation costs over a two year period. The MPSC must issue a final order within one year of the original filing.

Kentucky Rate Matters

Kentucky Base Rate Filing

In December 2009, KPCo filed a base rate case with the KPSC to increase base revenues by \$124 million annually based on an 11.75% return on common equity. The base rate case also requested recovery of deferred storm restoration expenses over a three-year period which total \$23 million as of June 30, 2010.

A settlement agreement was filed with the KPSC to increase base revenue by \$64 million annually based on a 10.5% return on common equity. The settlement agreement included recovery of \$23 million of deferred storm restoration expenses over five years. In June 2010, the KPSC approved the settlement agreement as filed. New rates became effective the first billing cycle of July 2010.

FERC Rate Matters

Regional Transmission Rate Proceedings at the FERC

Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund

In 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected, at the FERC's direction, load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 2006. Intervenor objected to the temporary SECA rates. The FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies recognized gross SECA revenues of \$220 million from 2004 through 2006 when the SECA rates terminated leaving the AEP East companies and ultimately their internal load retail customers to make up the shortfall in revenues.

In 2006, a FERC Administrative Law Judge (ALJ) issued an initial decision finding that the rate design for the recovery of SECA charges was flawed and that a large portion of the "lost revenues" reflected in the SECA rates should not have been recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory and

that new compliance filings and refunds should be made. The ALJ also found that any unpaid SECA rates must be paid in the recommended reduced amount.

AEP filed briefs jointly with other affected companies noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision. In May 2010, the FERC issued an order that generally supports AEP's position and requires a compliance filing to be filed with the FERC by August 2010. In June 2010, AEP and other affected companies filed a joint request for rehearing with the FERC regarding certain matters including a request to clarify the method for determining the amount of such revenues. The rehearing also requested the FERC to clarify that interest may be added to SECA charges originally billed to but never paid by Green Mountain Energy (reassigned to British Petroleum Energy). Eight other groups also filed requests for rehearing with the FERC.

The AEP East companies provided reserves for net refunds for SECA settlements applicable to the remaining \$108 million of SECA revenues collected. Based on the AEP East companies' analysis of the May 2010 order, management believes that the reserve is adequate to pay the refunds, including interest, that will be required should the May 2010 order be made final as issued by the FERC. Management cannot predict the ultimate outcome of this proceeding at the FERC which could impact future net income and cash flows.

Modification of the Transmission Agreement (TA)

APCo, CSPCo, I&M, KPCo and OPCo are parties to the TA that provides for a sharing of the cost of transmission lines operated at 138-kV and above and transmission stations containing extra-high voltage facilities. In June 2009, AEPSC, on behalf of the parties to the TA, filed with the FERC a request to modify the TA. Under the proposed amendments, KGPCo and WPCo will be added as parties to the TA. In addition, the amendments would provide for the allocation of PJM transmission costs on the basis of the TA parties' 12-month coincident peak and reimburse transmission revenues based on individual cost of service instead of the MLR method used in the present TA. AEPSC requested the effective date to be the first day of the month following a final non-appealable FERC order. The delayed effective date was approved by the FERC when the FERC accepted the new TA for filing. Settlement discussions are in progress. Management is unable to predict whether the parties to the TA will experience regulatory lag and its effect on future net income and cash flows due to timing of the implementation of the modified TA by various state regulators.

PJM/MISO Market Flow Calculation Settlement Adjustments

During 2009, an analysis conducted by MISO and PJM discovered several instances of unaccounted for power flows on numerous coordinated flowgates. These flows affected the settlement data for congestion revenues and expenses and date back to the start of the MISO market in 2005. PJM has provided MISO an initial analysis of amounts they believe they owe MISO. MISO disputes PJM's methodology.

Settlement discussions between MISO and PJM have been unsuccessful, and as a result, in March 2010, MISO filed two related complaints against PJM at the FERC related to the above claim. MISO seeks to recover a total of approximately \$145 million from PJM. If PJM is held liable for these damages, PJM members, including the AEP East companies, may be billed for a share of the refunds or payments PJM is directed to make to MISO. AEP has intervened and filed a protest to one complaint. Management believes that MISO's claims are without merit and that PJM's right to recover any MISO damages from AEP and other members is limited. If the FERC orders a settlement above the AEP East companies' reserve related to their estimated portion of PJM additional costs, it could reduce future net income and cash flows and impact financial condition.

4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

We are subject to certain claims and legal actions arising in our ordinary course of business. In addition, our business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against us cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings

would have a material adverse effect on our financial statements. The Commitments, Guarantees and Contingencies note within our 2009 Annual Report should be read in conjunction with this report.

GUARANTEES

We record liabilities for guarantees in accordance with the accounting guidance for “Guarantees.” There is no collateral held in relation to any guarantees in excess of our ownership percentages. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

Letters Of Credit

We enter into standby letters of credit with third parties. These letters of credit cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves. As the Parent, we issued all of these letters of credit in our ordinary course of business on behalf of our subsidiaries. We have two \$1.5 billion credit facilities, of which \$750 million may be issued under one credit facility as letters of credit. In June 2010, we canceled a facility that was scheduled to mature in March 2011 and entered into a new \$1.5 billion credit facility scheduled to mature in 2013 that allows for the issuance of up to \$600 million as letters of credit. As of June 30, 2010, the maximum future payments for letters of credit issued under the two \$1.5 billion credit facilities were \$149 million with maturities ranging from July 2010 to October 2011.

In June 2010, we reduced the \$627 million credit agreement to \$478 million. As of June 30, 2010, \$477 million of letters of credit with maturities ranging from November 2010 to April 2011 were issued by subsidiaries under this credit agreement to support variable rate Pollution Control Bonds.

Guarantees Of Third-Party Obligations

SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of approximately \$65 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine Mining Company (Sabine), a consolidated variable interest entity. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study, we estimate the reserves will be depleted in 2036 with final reclamation completed by 2046 at an estimated cost of approximately \$58 million. As of June 30, 2010, SWEPCo has collected approximately \$46 million through a rider for final mine closure and reclamation costs, of which \$2 million is recorded in Other Current Liabilities, \$22 million is recorded in Deferred Credits and Other Noncurrent Liabilities and \$22 million is recorded in Asset Retirement Obligations on our Condensed Consolidated Balance Sheets.

Sabine charges SWEPCo, its only customer, all of its costs. SWEPCo passes these costs to customers through its fuel clause.

Indemnifications and Other Guarantees

Contracts

We enter into several types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price. The status of certain sale agreements is discussed in the 2009 Annual Report “Dispositions” section of Note 7. These sale agreements include indemnifications with a maximum exposure related to the collective purchase price. This maximum exposure of approximately \$1 billion relates to the Bank of America (BOA) litigation (see “Enron Bankruptcy” section of this

note), of which the probable payment/performance risk is \$445 million and is recorded in Deferred Credits and Other Noncurrent Liabilities on our Condensed Consolidated Balance Sheets as of June 30, 2010. The remaining exposure is remote. There are no material liabilities recorded for any indemnifications other than amounts recorded related to the BOA litigation.

Master Lease Agreements

We lease certain equipment under master lease agreements. GE Capital Commercial Inc. (GE) notified us in November 2008 that they elected to terminate our Master Leasing Agreements in accordance with the termination rights specified within the contract. In 2011, we will be required to purchase all equipment under the lease and pay GE an amount equal to the unamortized value of all equipment then leased. In December 2008 and 2009, we signed new master lease agreements that include lease terms of up to 10 years.

For equipment under the GE master lease agreements that expire in 2011, the lessor is guaranteed receipt of up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair value of the leased equipment is below the unamortized balance at the end of the lease term, we are committed to pay the difference between the fair value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. Under the new master lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, we are committed to pay the difference between the actual fair value and the residual value guarantee. At June 30, 2010, the maximum potential loss for these lease agreements was approximately \$3 million assuming the fair value of the equipment is zero at the end of the lease term. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance.

Railcar Lease

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years via the renewal options. The future minimum lease obligations are \$18 million for I&M and \$20 million for SWEPCo for the remaining railcars as of June 30, 2010.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines from approximately 84% under the current five year lease term to 77% at the end of the 20-year term of the projected fair value of the equipment. I&M and SWEPCo have assumed the guarantee under the return-and-sale option. I&M's maximum potential loss related to the guarantee is approximately \$12 million (\$8 million, net of tax) and SWEPCo's is approximately \$13 million (\$9 million, net of tax) assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, we believe that the fair value would produce a sufficient sales price to avoid any loss.

We have other railcar lease arrangements that do not utilize this type of financing structure.

ENVIRONMENTAL CONTINGENCIES

Federal EPA Complaint and Notice of Violation

The Federal EPA, certain special interest groups and a number of states alleged that APCo, CSPCo, I&M and OPCo modified certain units at their coal-fired generating plants in violation of the NSR requirements of the CAA. Cases with similar allegations against CSPCo, Dayton Power and Light Company and Duke Energy Ohio, Inc. were also filed related to their jointly-owned units. The cases were settled with the exception of a case involving a jointly-owned Beckjord unit which had a liability trial. Following the trial, the jury found no liability for claims made against the jointly-owned Beckjord unit. Following a second liability trial in 2009, the jury again found no liability at

the jointly-owned Beckjord unit. The defendants and the plaintiffs appealed to the Seventh Circuit Court of Appeals. Beckjord is operated by Duke Energy Ohio, Inc. We are unable to determine a range of potential losses that are reasonably possible of occurring.

SWEPCo Notice of Enforcement and Notice of Citizen Suit

In 2005, two special interest groups, Sierra Club and Public Citizen, filed a complaint alleging violations of the CAA at SWEPCo's Welsh Plant. In 2008, a consent decree resolved all claims in the case and in the pending appeal of an altered permit for the Welsh Plant. The consent decree required SWEPCo to install continuous particulate emission monitors at the Welsh Plant, secure 65 MW of renewable energy capacity, fund \$2 million in emission reduction, energy efficiency or environmental mitigation projects and pay a portion of plaintiffs' attorneys' fees and costs.

The Federal EPA issued a Notice of Violation (NOV) based on alleged violations of a percent sulfur in fuel limitation and the heat input values listed in a previous state permit. The NOV also alleges that a permit alteration issued by the Texas Commission on Environmental Quality in 2007 was improper. In March 2008, SWEPCo met with the Federal EPA to discuss the alleged violations. The Federal EPA did not object to the settlement of similar alleged violations in the federal citizen suit. We are unable to predict the timing of any future action by the Federal EPA. We are unable to determine a range of potential losses that are reasonably possible of occurring.

Carbon Dioxide Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in Federal District Court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The trial court dismissed the lawsuits.

In September 2009, the Second Circuit Court of Appeals issued a ruling on appeal remanding the cases to the Federal District Court for the Southern District of New York. The Second Circuit held that the issues of climate change and global warming do not raise political questions and that Congress' refusal to regulate CO2 emissions does not mean that plaintiffs must wait for an initial policy determination by Congress or the President's administration to secure the relief sought in their complaints. The court stated that Congress could enact comprehensive legislation to regulate CO2 emissions or that the Federal EPA could regulate CO2 emissions under existing CAA authorities and that either of these actions could override any decision made by the district court under federal common law. The Second Circuit did not rule on whether the plaintiffs could proceed with their state common law nuisance claims. The defendants' petition for rehearing was denied. We believe the actions are without merit and intend to continue to defend against the claims. The Solicitor General requested an extension of time to file a petition for review by the U.S. Supreme Court and the remaining defendants received a similar extension of time. Petitions are currently due on or before August 2, 2010.

In October 2009, the Fifth Circuit Court of Appeals reversed a decision by the Federal District Court for the District of Mississippi dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that CO2 emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs' complaint to a coordinate branch of government and that no initial policy determination was required to adjudicate these claims. The court granted petitions for rehearing. An additional recusal left the Fifth Circuit without a quorum to reconsider the decision and the appeal was dismissed, leaving the district court's decision in place. We were initially dismissed from this case without prejudice, but are named as a defendant in a pending fourth amended complaint. Unless the plaintiffs elect to file a petition for review by the U.S. Supreme Court, there will be no further proceedings in this case.

We are unable to determine a range of potential losses that are reasonably possible of occurring.

Alaskan Villages' Claims

In 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil and gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of CO₂ contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of \$95 million to \$400 million. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. The plaintiffs appealed the decision. We believe the action is without merit and intend to defend against the claims. We are unable to determine a range of potential losses that are reasonably possible of occurring.

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, our generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and nonhazardous materials. We currently incur costs to dispose of these substances safely.

In March 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. In May 2008, I&M started remediation work in accordance with a plan approved by MDEQ. I&M recorded approximately \$11 million of expense prior to January 1, 2010, \$3 million of which I&M recorded in March 2009. As the remediation work is completed, I&M's cost may continue to increase as new information becomes available concerning either the level of contamination at the site or changes in the scope of remediation required by the MDEQ. I&M cannot predict the amount of additional cost, if any.

Amos Plant – Request to Show Cause

In March 2010, we received a request to show cause from the Federal EPA alleging that certain reporting requirements under Superfund and the Emergency Planning and Community Right-to-Know Act had been violated and inviting us to engage in settlement negotiations. The request includes a proposed civil penalty of approximately \$300 thousand. We indicated our willingness to engage in good faith negotiations and met with representatives of the Federal EPA. We have not admitted that any violations occurred or that the amount of the proposed penalty is reasonable. We are unable to determine a range of potential losses that are reasonably possible of occurring.

Defective Environmental Equipment

As part of our continuing environmental investment program, we chose to retrofit wet flue gas desulfurization systems on several units utilizing the jet bubbling reactor (JBR) technology. The following plants have been scheduled for the installation of the JBR technology or are currently utilizing JBR retrofits:

| Plant Name | Plant Owners | JBRs Installed/ Scheduled for Installation |
|-----------------|--|---|
| Cardinal | OPCo/Buckeye Power, Inc. | 3 |
| Conesville | CSPCo/Dayton Power and Light Company/ Duke Energy Ohio, Inc. | 1 |
| Clifty Creek | Indiana-Kentucky Electric Corporation | 2 |
| Kyger Creek | Ohio Valley Electric Corporation | 2 |
| Muskingum River | | |
| (a) | OPCo | 1 |
| Big Sandy (a) | KPCo | 1 |

(a) Contracts for the Muskingum River and Big Sandy Projects have been temporarily suspended during the early development stages of the projects.

The retrofits on two of the Cardinal Plant units and the Conesville Plant unit are operational. Due to unexpected operating results, we completed an extensive review of the design and manufacture of the JBR internal components. Our review concluded that there are fundamental design deficiencies and that inferior and/or inappropriate materials were selected for the internal fiberglass components. We initiated discussions with Black & Veatch, the original equipment manufacturer, to develop a repair or replacement corrective action plan. We intend to pursue our contractual and other legal remedies if we are unable to resolve these issues with Black & Veatch. If we are unsuccessful in obtaining reimbursement for the work required to remedy this situation, the cost of repair or replacement could have an adverse impact on construction costs, net income, cash flows and financial condition. We are unable to determine a range of potential losses that are reasonably possible of occurring.

NUCLEAR CONTINGENCIES

I&M owns and operates the two-unit 2,191 MW Cook Plant under licenses granted by the Nuclear Regulatory Commission. We have a significant future financial commitment to dispose of SNF and to safely decommission and decontaminate the plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. The operation of a nuclear facility also involves special risks, potential liabilities and specific regulatory and safety requirements. By agreement, I&M is partially liable, together with all other electric utility companies that own nuclear generating units, for a nuclear power plant incident at any nuclear plant in the U.S. Should a nuclear incident occur at any nuclear power plant in the U.S., the resultant liability could be substantial.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in significant turbine damage and a small fire on the electric generator. This equipment, located in the

turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and are within the vendor's warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately \$395 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process. I&M repaired Unit 1 and it resumed operations in December 2009 at slightly reduced power. The Unit 1 rotors were repaired and reinstalled due to the extensive lead time required to manufacture and install new turbine rotors. As a result, the replacement of the repaired turbine rotors and other equipment is scheduled for the Unit 1 planned outage in the fall of 2011.

I&M maintains property insurance through NEIL with a \$1 million deductible. As of June 30, 2010, we recorded \$53 million in Prepayments and Other Current Assets on our Condensed Consolidated Balance Sheets representing recoverable amounts under the property insurance policy. Through June 30, 2010, I&M received partial payments of \$203 million from NEIL for the cost incurred to date to repair the property damage.

I&M also maintains a separate accidental outage policy with NEIL. In 2009, I&M recorded \$185 million in revenue under the policy and reduced the cost of replacement power in customers' bills by \$78 million.

NEIL is reviewing claims made under the insurance policies to ensure that claims associated with the outage are covered by the policies. The treatment of property damage costs, replacement power costs and insurance proceeds will be the subject of future regulatory proceedings in Indiana and Michigan. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if any future regulatory proceedings are adverse, it could have an adverse impact on net income, cash flows and financial condition.

OPERATIONAL CONTINGENCIES

Fort Wayne Lease

Since 1975, I&M has leased certain energy delivery assets from the City of Fort Wayne, Indiana under a long-term lease that expired on February 28, 2010. I&M has been negotiating with Fort Wayne to purchase the assets at the end of the lease, but no agreement has been reached. Fort Wayne issued a technical notice of default under the lease to I&M in August 2009. I&M responded to Fort Wayne in October 2009 that it did not agree there was a default under the lease. In October 2009, I&M filed for declaratory and injunctive relief in Indiana state court. The parties agreed to submit this matter to mediation. In February 2010, the court issued a stay to continue mediation. I&M is making monthly payments to an escrow account in lieu of rent. I&M will seek recovery in rates for any amount it may pay related to this dispute. We are unable to determine a range of potential losses that are reasonably possible of occurring.

Enron Bankruptcy

In 2001, we purchased Houston Pipeline Company (HPL) from Enron. Various HPL-related contingencies and indemnities from Enron remained unsettled at the date of Enron's bankruptcy. In connection with our acquisition of HPL, we entered into an agreement with BAM Lease Company, which granted HPL the exclusive right to use approximately 55 billion cubic feet (BCF) of cushion gas required for the normal operation of the Bammel gas storage facility. At the time of our acquisition of HPL, BOA and certain other banks (the BOA Syndicate) and Enron entered into an agreement granting HPL the exclusive use of the cushion gas. Also at the time of our acquisition, Enron and the BOA Syndicate released HPL from all prior and future liabilities and obligations in connection with the financing arrangement. After the Enron bankruptcy, the BOA Syndicate informed HPL of a purported default by Enron under the terms of the financing arrangement. This dispute is being litigated in the Enron bankruptcy proceedings and in federal courts in Texas and New York.

In February 2004, Enron filed Notices of Rejection regarding the cushion gas exclusive right to use agreement and other incidental agreements. We objected to Enron's attempted rejection of these agreements and filed an adversary proceeding contesting Enron's right to reject these agreements.

In 2003, AEP filed a lawsuit against BOA in the United States District Court for the Southern District of Texas. BOA led the lending syndicate involving the monetization of the cushion gas to Enron and its subsidiaries. The lawsuit asserts that BOA made misrepresentations and engaged in fraud to induce and promote the stock sale of HPL, that BOA directly benefited from the sale of HPL and that AEP undertook the stock purchase and entered into the cushion gas arrangement with Enron and BOA based on misrepresentations that BOA made about Enron's financial condition.

that BOA knew or should have known were false. In 2005, the Judge entered an order severing and transferring the declaratory judgment claims involving the right to use and cushion gas consent agreements to the Southern District of New York and retaining in the Southern District of Texas the four counts alleging breach of contract, fraud and negligent misrepresentation. Trial in federal court in Texas was continued pending a decision in the New York case.

In 2007, the judge in the New York action issued a decision on all claims, including those that were pending trial in Texas, granting BOA summary judgment and dismissing our claims. In August 2008, the court entered a final judgment of \$346 million. We appealed and posted a bond covering the amount of the judgment entered against us. In May 2009, the judge awarded \$20 million of attorneys' fees to BOA. We appealed this award and posted bond covering that amount. In September 2009, the United States Court of Appeals for the Second Circuit heard oral argument on our appeal.

The liability for the BOA litigation was \$445 million and \$441 million including interest at June 30, 2010 and December 31, 2009, respectively. These liabilities are included in Deferred Credits and Other Noncurrent Liabilities on our Condensed Consolidated Balance Sheets.

Natural Gas Markets Lawsuits

In 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County California Superior Court against numerous energy companies, including AEP, alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP was dismissed from the case. A number of similar cases were also filed in California and in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. AEP (or a subsidiary) is among the companies named as defendants in some of these cases. These cases are at various pre-trial stages. In 2008, we settled all of the cases pending against us in California. The settlements did not impact 2008 earnings due to provisions made in prior periods. We will continue to defend each remaining case where an AEP company is a defendant. We believe the provision we have for the remaining cases is adequate. We are unable to determine a range of potential losses that are reasonably possible of occurring.

5. ACQUISITION AND DISPOSITIONS

ACQUISITION

2010

Valley Electric Membership Corporation (Utility Operations segment)

In November 2009, SWEPCo signed a letter of intent to purchase the transmission and distribution assets of Valley Electric Membership Corporation (VEMCO). The current estimate of the purchase is approximately \$100 million, plus the assumption of certain liabilities, subject to adjustments at closing. Consummation of the transaction is subject to regulatory approval by the LPSC, the APSC, the Rural Utilities Service, the National Rural Utilities Cooperative Finance Corporation and the FERC. In January 2010, the VEMCO members approved the transaction. In the second quarter of 2010, a purchase and sales agreement was signed and a joint application between SWEPCo and VEMCO was filed with the LPSC. SWEPCo will seek recovery from Louisiana customers for all costs related to this acquisition. VEMCO services approximately 30,000 customers in Louisiana. SWEPCo expects to complete the transaction in the third quarter of 2010 upon receipt of regulatory approvals.

2009

None

54

DISPOSITIONS

2010

Electric Transmission Texas LLC (ETT) (Utility Operations segment)

TCC and TNC sold \$64 million and \$71 million, respectively, of transmission facilities to ETT for the six months ended June 30, 2010. There were no gains or losses recorded on these transactions.

Intercontinental Exchange, Inc. (ICE) (All Other)

In April 2010, we sold our remaining 138,000 shares of ICE and recognized a \$16 million gain (\$10 million, net of tax). We recorded the gain in Interest and Investment Income on our Condensed Consolidated Statements of Income for the three months ended June 30, 2010.

2009

Electric Transmission Texas LLC (ETT) (Utility Operations segment)

TCC and TNC sold \$91 million and \$1 million, respectively, of transmission facilities to ETT for the six months ended June 30, 2009. There were no gains or losses recorded on these transactions.

6. BENEFIT PLANS

Components of Net Periodic Benefit Cost

The following tables provide the components of our net periodic benefit cost for the plans for the three and six months ended June 30, 2010 and 2009:

| | Pension Plans | | Other Postretirement Benefit Plans | |
|---------------------------------------|-----------------------------|-------|------------------------------------|-------|
| | Three Months Ended June 30, | | Three Months Ended June 30, | |
| | 2010 | 2009 | 2010 | 2009 |
| | (in millions) | | | |
| Service Cost | \$ 27 | \$ 26 | \$ 11 | \$ 11 |
| Interest Cost | 64 | 64 | 28 | 28 |
| Expected Return on Plan Assets | (78) | (81) | (26) | (20) |
| Amortization of Transition Obligation | - | - | 7 | 6 |
| Amortization of Net Actuarial Loss | 23 | 15 | 7 | 10 |
| Net Periodic Benefit Cost | \$ 36 | \$ 24 | \$ 27 | \$ 35 |

| | Pension Plans | | Other Postretirement Benefit Plans | |
|---------------|---------------------------|-------|------------------------------------|-------|
| | Six Months Ended June 30, | | Six Months Ended June 30, | |
| | 2010 | 2009 | 2010 | 2009 |
| | (in millions) | | | |
| Service Cost | \$ 55 | \$ 52 | \$ 23 | \$ 21 |
| Interest Cost | 127 | 127 | 56 | 55 |

| | | | | |
|--|-------|-------|-------|-------|
| Expected Return on Plan Assets | (156) | (161) | (52) | (40) |
| Amortization of Transition Obligation | - | - | 14 | 13 |
| Amortization of Net Actuarial Loss | 45 | 30 | 14 | 21 |
| Net Periodic Benefit Cost | \$ 71 | \$ 48 | \$ 55 | \$ 70 |

7. BUSINESS SEGMENTS

As outlined in our 2009 Annual Report, our primary business is our electric utility operations. Within our Utility Operations segment, we centrally dispatch generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. While our Utility Operations segment remains our primary business segment, other segments include our AEP River Operations

segment with significant barging activities and our Generation and Marketing segment, which includes our nonregulated generating, marketing and risk management activities primarily in the ERCOT market area. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

Our reportable segments and their related business activities are as follows:

Utility Operations

- Generation of electricity for sale to U.S. retail and wholesale customers.
- Electricity transmission and distribution in the U.S.

AEP River Operations

- Commercial barging operations that transport coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers.

Generation and Marketing

- Wind farms and marketing and risk management activities primarily in ERCOT.

The remainder of our activities is presented as All Other. While not considered a business segment, All Other includes:

- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense, and other nonallocated costs.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts are financial derivatives which gradually settle and completely expire in 2011.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

The tables below present our reportable segment information for the three and six months ended June 30, 2010 and 2009 and balance sheet information as of June 30, 2010 and December 31, 2009. These amounts include certain estimates and allocations where necessary.

| | Utility Operations | Nonutility Operations Generation AEP River Operations | and Marketing | All Other (a) | Reconciling Adjustments | Consolidated |
|----------------------------------|-----------------------|---|------------------|------------------|----------------------------|--------------|
| | | | (in millions) | | | |
| Three Months Ended June 30, 2010 | | | | | | |
| Revenues from: | | | | | | |
| External Customers | \$ 3,186 | \$ 127 | \$ 42 | \$ 5 | \$ - | \$ 3,360 |
| Other Operating Segments | 25 | 5 | - | (1) | (29) | - |
| Total Revenues | \$ 3,211 | \$ 132 | \$ 42 | \$ 4 | \$ (29) | \$ 3,360 |
| Net Income (Loss) | \$ 132 | \$ (1) | \$ 7 | \$ (1) | \$ - | \$ 137 |

Nonutility Operations
Generation
Utility and All Other Reconciling

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| | Operations | AEP River Operations | Marketing | (a) | Adjustments | Consolidated |
|------------------------------------|--------------|----------------------------|-----------|---------|-------------|--------------|
| (in millions) | | | | | | |
| Three Months Ended June 30, 2009 | | | | | | |
| Revenues from: | | | | | | |
| External Customers | \$ 3,035 (d) | \$ 105 | \$ 58 | \$ 4 | \$ - | \$ 3,202 |
| Other Operating Segments | 21 (d) | 3 | 1 | 5 | (30) | - |
| Total Revenues | \$ 3,056 | \$ 108 | \$ 59 | \$ 9 | \$ (30) | \$ 3,202 |
| Income (Loss) Before Extraordinary | | | | | | |
| Loss | \$ 327 | \$ 1 | \$ 4 | \$ (10) | \$ - | \$ 322 |
| Extraordinary Loss, Net of Tax | (5) | - | - | - | - | (5) |
| Net Income (Loss) | \$ 322 | \$ 1 | \$ 4 | \$ (10) | \$ - | \$ 317 |

| | | Utility Operations | Nonutility Operations Generation AEP River Operations | and Marketing (in millions) | All Other (a) | Reconciling Adjustments | Consolidated | | | | | |
|--------------------------------|----|-----------------------|---|-----------------------------------|------------------|----------------------------|--------------|------|----|------|----|-------|
| Six Months Ended June 30, 2010 | | | | | | | | | | | | |
| Revenues from: | | | | | | | | | | | | |
| External Customers | \$ | 6,592 | \$ | 248 | \$ | 89 | \$ | - | \$ | - | \$ | 6,929 |
| Other Operating Segments | | 45 | | 10 | | - | | 7 | | (62) | | - |
| Total Revenues | \$ | 6,637 | \$ | 258 | \$ | 89 | \$ | 7 | \$ | (62) | \$ | 6,929 |
| Net Income (Loss) | \$ | 476 | \$ | 2 | \$ | 17 | \$ | (12) | \$ | - | \$ | 483 |

| | | Utility Operations | Nonutility Operations Generation AEP River Operations | and Marketing (in millions) | All Other (a) | Reconciling Adjustments | Consolidated | | | | | |
|------------------------------------|----|-----------------------|---|-----------------------------------|------------------|----------------------------|--------------|------|----|------|----|-------|
| Six Months Ended June 30, 2009 | | | | | | | | | | | | |
| Revenues from: | | | | | | | | | | | | |
| External Customers | \$ | 6,302 (d) | \$ | 228 | \$ | 145 | \$ | (15) | \$ | - | \$ | 6,660 |
| Other Operating Segments | | 21 (d) | | 9 | | 6 | | 27 | | (63) | | - |
| Total Revenues | \$ | 6,323 | \$ | 237 | \$ | 151 | \$ | 12 | \$ | (63) | \$ | 6,660 |
| Income (Loss) Before Extraordinary | | | | | | | | | | | | |
| Loss | \$ | 673 | \$ | 12 | \$ | 28 | \$ | (28) | \$ | - | \$ | 685 |
| Extraordinary Loss, Net of Tax | | (5) | | - | | - | | - | | - | | (5) |
| Net Income (Loss) | \$ | 668 | \$ | 12 | \$ | 28 | \$ | (28) | \$ | - | \$ | 680 |

| | Nonutility Operations Generation | | | | Reconciling | | |
|--|-------------------------------------|----------------------------|------------------|------------------|--------------------|--|--------------|
| | Utility Operations | AEP River Operations | and Marketing | All Other (a) | Adjustments (b) | | Consolidated |
| | (in millions) | | | | | | |
| June 30, 2010 | | | | | | | |
| Total Property, Plant and Equipment | \$ 51,529 | \$ 527 | \$ 584 | \$ 10 | \$ (250) | | \$ 52,400 |
| Accumulated Depreciation and Amortization | 17,431 | 99 | 183 | 9 | (40) | | 17,682 |
| Total Property, Plant and Equipment - Net | \$ 34,098 | \$ 428 | \$ 401 | \$ 1 | \$ (210) | | \$ 34,718 |
| Total Assets | \$ 47,994 | \$ 565 | \$ 851 | \$ 15,344 | \$ (14,817) (c) | | \$ 49,937 |

Nonutility Operations

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| | Utility Operations | AEP River Operations | Generation and Marketing | All Other (a) (in millions) | Reconciling Adjustments (b) | Consolidated |
|---|-----------------------|----------------------------|--------------------------------|-----------------------------------|-----------------------------------|--------------|
| December 31, 2009 | | | | | | |
| Total Property, Plant and Equipment | \$ 50,905 | \$ 436 | \$ 571 | \$ 10 | \$ (238) | \$ 51,684 |
| Accumulated Depreciation and Amortization | 17,110 | 88 | 168 | 8 | (34) | 17,340 |
| Total Property, Plant and Equipment - Net | \$ 33,795 | \$ 348 | \$ 403 | \$ 2 | \$ (204) | \$ 34,344 |
| Total Assets | \$ 46,930 | \$ 495 | \$ 779 | \$ 15,094 | \$ (14,950) (c) | \$ 48,348 |

(a) All Other includes:

- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense, and other nonallocated costs.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts are financial derivatives which gradually settle and completely expire in 2011.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

(b) Includes eliminations due to an intercompany capital lease.

(c) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEP's investments in subsidiary companies.

(d) PSO and SWEPCo transferred certain existing ERCOT energy marketing contracts to AEP Energy Partners, Inc. (AEPEP) (Generation and Marketing segment) and entered into intercompany financial and physical purchase and sales agreements with AEPEP. As a result, we reported third-party net purchases or sales activity for these energy marketing contracts as Revenues from External Customers for the Utility Operations segment. This was offset by the Utility Operations segment's related net sales (purchases) for these contracts with AEPEP in Revenues from Other Operating Segments of \$(1) million and \$(6) million for the three and six months ended, 2009, respectively. The Generation and Marketing segment also reported these purchase or sales contracts with Utility Operations as Revenues from Other Operating Segments. These affiliated contracts between PSO and SWEPCo with AEPEP ended in December 2009.

8. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

We are exposed to certain market risks as a major power producer and marketer of wholesale electricity, coal and emission allowances. These risks include commodity price risk, interest rate risk, credit risk and to a lesser extent foreign currency exchange risk. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates. We manage these risks using derivative instruments.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Our strategy surrounding the use of derivative instruments focuses on managing our risk exposures, future cash flows and creating value based on our open trading positions by utilizing both economic and formal hedging strategies. To accomplish our objectives, we primarily employ risk management contracts including physical forward purchase and sale contracts, financial forward purchase and sale contracts and financial swap instruments. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

We enter into electricity, coal, natural gas, interest rate and to a lesser degree heating oil, gasoline, emission allowance and other commodity contracts to manage the risk associated with our energy business. We enter into interest rate derivative contracts in order to manage the interest rate exposure associated with our commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as they are related to energy risk management activities. We also engage in risk management of interest rate risk associated with debt financing and foreign currency risk associated with future purchase obligations denominated in foreign currencies. For disclosure purposes, these risks are grouped as "Interest Rate and Foreign Currency." The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with our established risk management policies as approved by the Finance Committee of AEP's Board of Directors.

The following table represents the gross notional volume of our outstanding derivative contracts as of June 30, 2010 and December 31, 2009:

| Notional Volume of Derivative Instruments | | | |
|---|-------------------------|----------------------|--------------------|
| | June 30, 2010 | December 31, 2009 | Unit of Measure |
| | Volume (in millions) | | |
| Commodity: | | | |
| Power | 935 | 589 | MWHs |

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| | | | |
|---------------------------------------|--------|--------|---------|
| Coal | 71 | 60 | Tons |
| Natural Gas | 144 | 127 | MMBtus |
| Heating Oil and Gasoline | 7 | 6 | Gallons |
| Interest Rate | \$ 191 | \$ 216 | USD |
| Interest Rate and Foreign Currency | \$ 423 | \$ 83 | USD |

Fair Value Hedging Strategies

We enter into interest rate derivative transactions as part of an overall strategy to manage the mix of fixed-rate and floating-rate debt. Certain interest rate derivative transactions effectively modify our exposure to interest rate risk by converting a portion of our fixed-rate debt to a floating rate. Provided specific criteria are met, these interest rate derivatives are designated as fair value hedges.

Cash Flow Hedging Strategies

We enter into and designate as cash flow hedges certain derivative transactions for the purchase and sale of electricity, coal, heating oil and natural gas (“Commodity”) in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. We monitor the potential impacts of commodity price changes and, where appropriate, enter into derivative transactions to protect profit margins for a portion of future electricity sales and fuel or energy purchases. We do not hedge all commodity price risk.

Our vehicle fleet and barge operations are exposed to gasoline and diesel fuel price volatility. We enter into financial gasoline and heating oil derivative contracts in order to mitigate price risk of our future fuel purchases. We do not hedge all fuel price risk. For disclosure purposes, these contracts are included with other hedging activity as “Commodity.”

We enter into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify our exposure to interest rate risk by converting a portion of our floating-rate debt to a fixed rate. We also enter into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. Our anticipated fixed-rate debt offerings have a high probability of occurrence as the proceeds will be used to fund existing debt maturities and projected capital expenditures. We do not hedge all interest rate exposure.

At times, we are exposed to foreign currency exchange rate risks primarily when we purchase certain fixed assets from foreign suppliers. In accordance with our risk management policy, we may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency’s appreciation against the dollar. We do not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON OUR FINANCIAL STATEMENTS

The accounting guidance for “Derivatives and Hedging” requires recognition of all qualifying derivative instruments as either assets or liabilities in the balance sheet at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of our derivative instruments, we also apply valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract’s term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with our estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions,

margin requirements and the timing of settlement of our risk management contracts.

According to the accounting guidance for “Derivatives and Hedging,” we reflect the fair values of our derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, we are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the June 30, 2010 and December 31, 2009 balance sheets, we netted \$19 million and \$12 million, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and \$96 million and \$98 million, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following tables represent the gross fair value impact of our derivative activity on our Condensed Consolidated Balance Sheets as of June 30, 2010 and December 31, 2009:

Fair Value of Derivative Instruments
June 30, 2010

| Balance Sheet Location | Risk Management Contracts Commodity (a) | Hedging Contracts Commodity (a) | Interest Rate and Foreign Currency (a)(c) (in millions) | Other (a) (b) | Total |
|---|--|------------------------------------|---|------------------|--------|
| | | | | | |
| Current Risk Management Assets | \$ 1,051 | \$ 14 | \$ 3 | \$ (818) | \$ 250 |
| Long-term Risk Management Assets | 691 | 7 | 1 | (291) | 408 |
| Total Assets | 1,742 | 21 | 4 | (1,109) | 658 |
| Current Risk Management Liabilities | 978 | 15 | 3 | (876) | 120 |
| Long-term Risk Management Liabilities | 540 | 3 | 2 | (368) | 177 |
| Total Liabilities | 1,518 | 18 | 5 | (1,244) | 297 |
| Total MTM Derivative Contract Net Assets (Liabilities) | \$ 224 | \$ 3 | \$ (1) | \$ 135 | \$ 361 |

Fair Value of Derivative Instruments
December 31, 2009

| Balance Sheet Location | Risk Management Contracts Commodity (a) | Hedging Contracts Interest Rate and Foreign (a)(c) | Other (a) (b) | Total |
|------------------------|--|--|------------------|-------|
| | | | | |

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| | | Commodity (a) | Currency (a) | | | | | | | |
|--|----|------------------|-----------------|-----|----|-----|----|---------|----|-----|
| | | | (in millions) | | | | | | | |
| Current Risk Management Assets | \$ | 1,078 | \$ | 13 | \$ | - | \$ | (831) | \$ | 260 |
| Long-term Risk Management Assets | | 614 | | - | | - | | (271) | | 343 |
| Total Assets | | 1,692 | | 13 | | - | | (1,102) | | 603 |
| Current Risk Management Liabilities | | 997 | | 17 | | 3 | | (897) | | 120 |
| Long-term Risk Management Liabilities | | 442 | | - | | 2 | | (316) | | 128 |
| Total Liabilities | | 1,439 | | 17 | | 5 | | (1,213) | | 248 |
| Total MTM Derivative Contract Net Assets | | | | | | | | | | |
| (Liabilities) | \$ | 253 | \$ | (4) | \$ | (5) | \$ | 111 | \$ | 355 |

- (a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the Condensed Consolidated Balance Sheet on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
- (b) Amounts represent counterparty netting of risk management and hedging contracts, associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging" and dedesignated risk management contracts.
- (c) At June 30, 2010, Risk Management Assets included \$4 million related to fair value hedging strategies while the remainder related to cash flow hedging strategies. At December 31, 2009, we only employed cash flow hedging strategies.

The table below presents our activity of derivative risk management contracts for the three and six months ended June 30, 2010 and 2009:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended June 30, 2010 and 2009

| Location of Gain (Loss) | 2010 | 2009 |
|--|---------------|-------|
| | (in millions) | |
| Utility Operations Revenue | \$ 7 | \$ 33 |
| Other Revenue | 8 | 5 |
| Regulatory Assets (a) | (14) | (18) |
| Regulatory Liabilities (a) | (4) | 3 |
| Total Gain (Loss) on Risk Management Contracts | \$ (3) | \$ 23 |

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Six Months Ended June 30, 2010 and 2009

| Location of Gain (Loss) | 2010 | 2009 |
|--|---------------|--------|
| | (in millions) | |
| Utility Operations Revenue | \$ 45 | \$ 99 |
| Other Revenue | 9 | 18 |
| Regulatory Assets (a) | (3) | (11) |
| Regulatory Liabilities (a) | 27 | 10 |
| Total Gain (Loss) on Risk Management Contracts | \$ 78 | \$ 116 |

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or non-current on the balance sheet.

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for “Derivatives and Hedging.” Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the Condensed Consolidated Statements of Income on an accrual basis.

Our accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, we designate a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in Revenues on a net basis on the Condensed Consolidated Statements of Income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in Revenues or Expenses on the Condensed Consolidated Statements of Income depending on the relevant facts and circumstances. However, unrealized and some realized gains and losses in regulated jurisdictions for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with the accounting guidance for “Regulated Operations.”

Accounting for Fair Value Hedging Strategies

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof attributable to a particular risk), the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item associated with the hedged risk impacts Net Income during the period of change.

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We record realized and unrealized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on our Condensed Consolidated Statements of Income. During the three and six months ended June 30, 2010 and 2009, we recognized a gain of \$4 million on our hedging instrument with an offsetting loss of \$4 million on our long-term debt. During the three and six months ended June 30, 2010, no hedge ineffectiveness was recognized. During the three and six months ended June 30, 2010 and 2009, we did not employ any fair value hedging strategies.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows attributable to a particular risk), we initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on our Condensed Consolidated Balance Sheets until the period the hedged item affects Net Income. We recognize any hedge ineffectiveness in Net Income immediately during the period of change, except in regulated jurisdictions where hedge ineffectiveness is recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivative contracts for the purchase and sale of electricity, coal, heating oil and natural gas designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on our Condensed Consolidated Statements of Income, or in Regulatory Assets or Regulatory Liabilities on our Condensed Consolidated Balance Sheets, depending on the specific nature of the risk being hedged. During the three and six months ended June 30, 2010 and 2009, we designated commodity derivatives as cash flow hedges.

We reclassify gains and losses on financial fuel derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on our Condensed Consolidated Balance Sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on our Condensed Consolidated Statements of Income. During the three and six months ended June 30, 2010 and 2009, we designated heating oil and gasoline derivatives as cash flow hedges.

We reclassify gains and losses on interest rate derivative hedges related to our debt financings from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During the three and six months ended June 30, 2010 and 2009, we designated interest rate derivatives as cash flow hedges.

The accumulated gains or losses related to our foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on our Condensed Consolidated Balance Sheets into Depreciation and Amortization expense on our Condensed Consolidated Statements of Income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During the three and six months ended June 30, 2010 and 2009, we designated foreign currency derivatives as cash flow hedges.

During the three and six months ended June 30, 2010 and 2009, hedge ineffectiveness was immaterial or nonexistent for all of the hedge strategies disclosed above.

The following tables provide details on designated, effective cash flow hedges included in AOCI on our Condensed Consolidated Balance Sheets and the reasons for changes in cash flow hedges for the three and six months ended June 30, 2010 and 2009. All amounts in the following table are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Three Months Ended June 30, 2010

| | Commodity | Interest Rate and Foreign Currency (in millions) | Total |
|--|-----------|---|---------|
| Balance in AOCI as of March 31, 2010 | \$ 2 | \$ (13) | \$ (11) |
| Changes in Fair Value Recognized in AOCI | 1 | (3) | (2) |
| Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet: | | | |
| Utility Operations Revenue | - | - | - |
| Other Revenue | (2) | - | (2) |
| Purchased Electricity for Resale | 1 | - | 1 |
| Interest Expense | - | 1 | 1 |
| Regulatory Assets (a) | - | - | - |
| Regulatory Liabilities (a) | - | - | - |
| Balance in AOCI as of June 30, 2010 | \$ 2 | \$ (15) | \$ (13) |

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Three Months Ended June 30, 2009

| | Commodity | Interest Rate and Foreign Currency (in millions) | Total |
|--|-----------|---|---------|
| Balance in AOCI as of March 31, 2009 | \$ 9 | \$ (28) | \$ (19) |
| Changes in Fair Value Recognized in AOCI | - | 15 | 15 |
| Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet: | | | |
| Utility Operations Revenue | (4) | - | (4) |
| Other Revenue | (4) | - | (4) |
| Purchased Electricity for Resale | 6 | - | 6 |
| Interest Expense | - | 2 | 2 |
| Regulatory Assets (a) | 1 | - | 1 |
| Regulatory Liabilities (a) | (2) | - | (2) |
| Balance in AOCI as of June 30, 2009 | \$ 6 | \$ (11) | \$ (5) |

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Six Months Ended June 30, 2010

| | Commodity | Interest Rate and Foreign Currency (in millions) | Total |
|--|-----------|---|---------|
| Balance in AOCI as of December 31, 2009 | \$ (2) | \$ (13) | \$ (15) |
| Changes in Fair Value Recognized in AOCI | 4 | (4) | - |
| Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet: | | | |
| Utility Operations Revenue | - | - | - |
| Other Revenue | (3) | - | (3) |
| Purchased Electricity for Resale | 2 | - | 2 |
| Interest Expense | - | 2 | 2 |
| Regulatory Assets (a) | 1 | - | 1 |
| Regulatory Liabilities (a) | - | - | - |
| Balance in AOCI as of June 30, 2010 | \$ 2 | \$ (15) | \$ (13) |

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Six Months Ended June 30, 2009

| | Commodity | Interest Rate and Foreign Currency (in millions) | Total |
|--|-----------|---|---------|
| Balance in AOCI as of December 31, 2008 | \$ 7 | \$ (29) | \$ (22) |
| Changes in Fair Value Recognized in AOCI | (3) | 15 | 12 |
| Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet: | | | |
| Utility Operations Revenue | (6) | - | (6) |
| Other Revenue | (6) | - | (6) |
| Purchased Electricity for Resale | 14 | - | 14 |
| Interest Expense | - | 3 | 3 |
| Regulatory Assets (a) | 3 | - | 3 |
| Regulatory Liabilities (a) | (3) | - | (3) |
| Balance in AOCI as of June 30, 2009 | \$ 6 | \$ (11) | \$ (5) |

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or non-current on the balance sheet.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on our Condensed Consolidated Balance Sheets at June 30, 2010 and December 31, 2009 were:

Impact of Cash Flow Hedges on our Condensed Consolidated Balance Sheet
June 30, 2010

| | Commodity | Interest Rate and Foreign Currency (in millions) | Total |
|--|-----------|---|-------|
| Hedging Assets (a) | \$ 11 | \$ - | \$ 11 |
| Hedging Liabilities (a) | (8) | (5) | (13) |
| AOCI Gain (Loss) Net of Tax | 2 | (15) | (13) |
| Portion Expected to be Reclassified to Net Income During the Next Twelve Months | (1) | (4) | (5) |

Impact of Cash Flow Hedges on our Condensed Consolidated Balance Sheet
December 31, 2009

| | Commodity | Interest Rate and Foreign Currency (in millions) | Total |
|--|-----------|---|-------|
| Hedging Assets (a) | \$ 8 | \$ - | \$ 8 |
| Hedging Liabilities (a) | (12) | (5) | (17) |
| AOCI Gain (Loss) Net of Tax | (2) | (13) | (15) |
| Portion Expected to be Reclassified to Net Income During the Next Twelve Months | (2) | (4) | (6) |

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on our Condensed Consolidated Balance Sheets.

The actual amounts that we reclassify from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of June 30, 2010, the maximum length of time that we are hedging (with contracts subject to the accounting guidance for “Derivatives and Hedging”) our exposure to variability in future cash flows related to forecasted transactions is 42 months.

Credit Risk

We limit credit risk in our wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. We use Moody’s, S&P and current market-based qualitative and quantitative data to assess the financial health of counterparties on an ongoing basis. If an external rating is not available, an internal rating is generated utilizing a quantitative tool developed by Moody’s to estimate probability of default that corresponds to an implied external agency credit rating.

We use standardized master agreements which may include collateral requirements. These master agreements facilitate the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate

guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds our established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with our credit policy. In addition, collateral agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Under a limited number of derivative and non-derivative counterparty contracts primarily related to our pre-2002 risk management activities and under the tariffs of the RTOs and Independent System Operators (ISOs), we are obligated to post an amount of collateral if our credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and our total exposure. On an ongoing basis, our risk management organization assesses the appropriateness of these collateral triggering items in contracts. We do not anticipate a downgrade below investment grade. The following table represents our aggregate fair value of such derivative contracts, the amount of collateral we would have been required to post for all derivative and non-derivative contracts if our credit ratings had declined below investment grade and how much was attributable to RTO and ISO activities as of June 30, 2010 and December 31, 2009:

| | June 30, 2010 | December 31, 2009 |
|--|------------------|----------------------|
| | (in millions) | |
| Liabilities for Derivative Contracts with Credit Downgrade Triggers | \$ 21 | \$ 10 |
| Amount of Collateral AEP Subsidiaries Would Have Been Required to Post | 25 | 34 |
| Amount Attributable to RTO and ISO Activities | 24 | 29 |

In addition, a majority of our non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event under outstanding debt in excess of \$50 million. On an ongoing basis, our risk management organization assesses the appropriateness of these cross-default provisions in our contracts. We do not anticipate a non-performance event under these provisions. The following table represents the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, the amount this exposure has been reduced by cash collateral we have posted and if a cross-default provision would have been triggered, the settlement amount that would be required after considering our contractual netting arrangements as of June 30, 2010 and December 31, 2009:

| | June 30, 2010 | December 31, 2009 |
|--|------------------|----------------------|
| | (in millions) | |
| Liabilities for Contracts with Cross Default Provisions Prior to Contractual | | |
| Netting Arrangements | \$ 557 | \$ 567 |
| Amount of Cash Collateral Posted | 25 | 15 |
| Additional Settlement Liability if Cross Default Provision is Triggered | 251 | 199 |

9. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

The accounting guidance for “Fair Value Measurements and Disclosures” establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be

completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

For our commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. We verify our price curves using these broker quotes and classify these fair values within Level 2 when substantially all of the fair value can be corroborated. We typically obtain multiple broker quotes, which are non-binding in nature, but are based on recent trades in the marketplace. When multiple broker quotes are obtained, we average the quoted bid and ask prices. In certain circumstances, we may discard a broker quote if it is a clear outlier. We use a historical correlation analysis between the broker quoted location and the illiquid locations and if the points are highly correlated we include these locations within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Long-dated and illiquid complex or structured transactions and FTRs can introduce the need for internally developed modeling inputs based upon extrapolations and assumptions of observable market data to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3.

We utilize our trustee's external pricing service in our estimate of the fair value of the underlying investments held in the nuclear trusts. Our investment managers review and validate the prices utilized by the trustee to determine fair value. We perform our own valuation testing to verify the fair values of the securities. We receive audit reports of our trustee's operating controls and valuation processes. The trustee uses multiple pricing vendors for the assets held in the trusts. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Fixed income securities do not trade on an exchange and do not have an official closing price. Pricing vendors calculate bond valuations using financial models and matrices. Fixed income securities are typically classified as Level 2 holdings because their valuation inputs are based on observable market data. Observable inputs used for valuing fixed income securities are benchmark yields, reported trades, broker/dealer quotes, issuer spreads, two-sided markets, benchmark securities, bids, offers, reference data, and economic events. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments.

Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equities. They are valued based on observable inputs primarily unadjusted quoted prices in active markets for identical assets.

Items classified as Level 2 are primarily investments in individual fixed income securities. These fixed income securities are valued using models with input data as follows:

| Type of Input | Type of Fixed Income Security | | |
|------------------------|-------------------------------|----------------|-----------------|
| | United States | | State and Local |
| | Government | Corporate Debt | Government |
| Benchmark Yields | X | X | X |
| Broker Quotes | X | X | X |
| Discount Margins | X | X | |
| Treasury Market Update | X | | |
| Base Spread | X | X | X |
| Corporate Actions | | X | |
| Ratings Agency Updates | | | X |

Prepayment
Schedule and

| | |
|---------|---|
| History | X |
|---------|---|

| | |
|-------------------|---|
| Yield Adjustments | X |
|-------------------|---|

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that we could realize in a current market exchange.

The book values and fair values of Long-term Debt as of June 30, 2010 and December 31, 2009 are summarized in the following table:

| | June 30, 2010 | | December 31, 2009 | |
|----------------|---------------|------------|-------------------|------------|
| | Book Value | Fair Value | Book Value | Fair Value |
| | (in millions) | | | |
| Long-term Debt | \$ 17,348 | \$ 18,821 | \$ 17,498 | \$ 18,479 |

Fair Value Measurements of Other Temporary Investments

Other Temporary Investments include marketable securities that we intend to hold for less than one year, investments by our protected cell of EIS and funds held by trustees primarily for the payment of debt.

The following is a summary of Other Temporary Investments:

| Other Temporary Investments | Cost | June 30, 2010 | | Estimated Fair Value |
|-----------------------------------|--------|------------------------|-------------------------|----------------------|
| | | Gross Unrealized Gains | Gross Unrealized Losses | |
| | | (in millions) | | |
| Restricted Cash (a) | \$ 195 | \$ - | \$ - | \$ 195 |
| Fixed Income Securities: | | | | |
| Mutual Funds | 68 | 1 | - | 69 |
| Variable Rate Demand Notes | 14 | - | - | 14 |
| Equity Securities - Mutual Funds | 18 | 2 | - | 20 |
| Total Other Temporary Investments | \$ 295 | \$ 3 | \$ - | \$ 298 |

| Other Temporary Investments | Cost | December 31, 2009 | | Estimated Fair Value |
|-----------------------------------|--------|------------------------|-------------------------|----------------------|
| | | Gross Unrealized Gains | Gross Unrealized Losses | |
| | | (in millions) | | |
| Restricted Cash (a) | \$ 223 | \$ - | \$ - | \$ 223 |
| Fixed Income Securities: | | | | |
| Mutual Funds | 57 | - | - | 57 |
| Variable Rate Demand Notes | 45 | - | - | 45 |
| Equity Securities: | | | | |
| Domestic | 1 | 15 | - | 16 |
| Mutual Funds | 18 | 4 | - | 22 |
| Total Other Temporary Investments | \$ 344 | \$ 19 | \$ - | \$ 363 |

(a) Primarily represents amounts held for the payment of debt.

The following table provides the activity for our debt and equity securities within Other Temporary Investments for the three and six months ended June 30, 2010 and 2009:

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|-----------------------------|------|---------------------------|------|
| | 2010 | 2009 | 2010 | 2009 |
| | (in millions) | | | |
| Proceeds From Investment Sales \$ | 16 | \$ - | \$ 257 | \$ - |
| Purchases of Investments | 24 | 1 | 221 | 1 |
| Gross Realized Gains on Investment Sales | 16 | - | 16 | - |
| Gross Realized Losses on Investment Sales | - | - | - | - |

In June 2009, we recorded \$9 million (\$6 million, net of tax) of other-than-temporary impairments of Other Temporary Investments for equity investments of our protected cell captive insurance company. At June 30, 2010, the fair value of fixed income securities are primarily debt based mutual funds with short and intermediate maturities and variable rate demand notes. Mutual funds may be sold and do not contain maturity dates for an individual investment holder.

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions allow us to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above when purchased).
- Maximum percentage invested in a specific type of investment.
- Prohibition of investment in obligations of AEP or its affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.
- Target asset allocation is 50% fixed income and 50% equity securities.

We maintain trust records for each regulatory jurisdiction. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification and other prudent investment objectives.

I&M records securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF at fair value. I&M classifies securities in the trust funds as available-for-sale due to their long-term purpose. The assessment of whether an investment in a debt security has suffered an other-than-temporary impairment is based on whether the investor has the intent to sell or more likely than not will be required to sell the debt security before recovery of its amortized costs. The assessment of whether an investment in an equity security has suffered an other-than-temporary impairment, among other things, is based on whether the investor has the ability and intent to hold the investment to recover its value. Other-than-temporary impairments for investments in both debt and equity securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the equity and debt investments held in these trusts and generally intends to sell debt securities in an unrealized loss position as part of a tax optimization strategy. I&M records unrealized gains and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. The gains,

losses or other-than-temporary impairments shown below did not affect earnings or AOCI. The trust assets are recorded by jurisdiction and may not be used for another jurisdiction's liabilities. Regulatory approval is required to withdraw decommissioning funds.

The following is a summary of nuclear trust fund investments at June 30, 2010 and December 31, 2009:

| | June 30, 2010 | | | December 31, 2009 | | |
|--|----------------------------|------------------------------|---|----------------------------|------------------------------|---|
| | Estimated Fair Value | Gross Unrealized Gains | Other-Than- Temporary Impairments | Estimated Fair Value | Gross Unrealized Gains | Other-Than- Temporary Impairments |
| | (in millions) | | | | | |
| Cash and Cash Equivalents | \$ 26 | \$ - | \$ - | \$ 14 | \$ - | \$ - |
| Fixed Income Securities: | | | | | | |
| United States Government | 473 | 31 | (1) | 401 | 13 | (4) |
| Corporate Debt | 60 | 6 | (6) | 57 | 5 | (2) |
| State and Local Government | 316 | 3 | - | 369 | 8 | 1 |
| Subtotal Fixed Income Securities | 849 | 40 | (7) | 827 | 26 | (5) |
| Equity Securities - Domestic | 516 | 194 | (122) | 551 | 234 | (119) |
| Spent Nuclear Fuel and Decommissioning Trusts | \$ 1,391 | \$ 234 | \$ (129) | \$ 1,392 | \$ 260 | \$ (124) |

The following table provides the securities activity within the decommissioning and SNF trusts for the three and six months ended June 30, 2010 and 2009:

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|--|-----------------------------|--------|---------------------------|--------|
| | 2010 | 2009 | 2010 | 2009 |
| | (in millions) | | | |
| Proceeds From Investment Sales \$ | 360 | \$ 253 | \$ 592 | \$ 411 |
| Purchases of Investments | 369 | 264 | 617 | 442 |
| Gross Realized Gains on Investment Sales | 1 | 6 | 6 | 9 |
| Gross Realized Losses on Investment Sales | - | 1 | - | 1 |

The adjusted cost of debt securities was \$809 million and \$801 million as of June 30, 2010 and December 31, 2009, respectively.

The fair value of debt securities held in the nuclear trust funds, summarized by contractual maturities, at June 30, 2010 was as follows:

| | Fair Value of Debt Securities (in millions) |
|--------------------|--|
| Within 1 year | \$ 12 |
| 1 year – 5 years | 262 |
| 5 years – 10 years | 304 |
| After 10 years | 271 |
| Total | \$ 849 |

Fair Value Measurements of Financial Assets and Liabilities

The following tables set forth, by level within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2010 and December 31, 2009. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in AEP's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2010

| | Level 1 | Level 2 | Level 3 (in millions) | Other | Total |
|---|----------|----------|--------------------------|----------|----------|
| Assets: | | | | | |
| Cash and Cash Equivalents (a) | \$ 593 | \$ 18 | \$ - | \$ 227 | \$ 838 |
| Other Temporary Investments | | | | | |
| Restricted Cash (a) | 161 | - | - | 34 | 195 |
| Fixed Income Securities: | | | | | |
| Mutual Funds | 69 | - | - | - | 69 |
| Variable Rate Demand Notes | - | 14 | - | - | 14 |
| Equity Securities - Mutual Funds (b) | 20 | - | - | - | 20 |
| Total Other Temporary Investments | 250 | 14 | - | 34 | 298 |
| Risk Management Assets | | | | | |
| Risk Management Commodity Contracts (c) | | | | | |
| (f) | 17 | 1,573 | 152 | (1,157) | 585 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (c) | 9 | 13 | - | (11) | 11 |
| Fair Value Hedges | - | 4 | - | - | 4 |
| Dedesignated Risk Management Contracts (d) | - | - | - | 58 | 58 |
| Total Risk Management Assets | 26 | 1,590 | 152 | (1,110) | 658 |
| Spent Nuclear Fuel and Decommissioning Trusts | | | | | |
| Cash and Cash Equivalents (e) | - | 14 | - | 12 | 26 |
| Fixed Income Securities: | | | | | |
| United States Government | - | 473 | - | - | 473 |
| Corporate Debt | - | 60 | - | - | 60 |
| State and Local Government | - | 316 | - | - | 316 |
| Subtotal Fixed Income Securities | - | 849 | - | - | 849 |
| Equity Securities - Domestic (b) | 516 | - | - | - | 516 |
| Total Spent Nuclear Fuel and Decommissioning Trusts | 516 | 863 | - | 12 | 1,391 |
| Total Assets | \$ 1,385 | \$ 2,485 | \$ 152 | \$ (837) | \$ 3,185 |

Liabilities:

| Risk Management Liabilities | | | | | |
|---|----|----|----|-------|-------------------------|
| Risk Management Commodity Contracts (c) | | | | | |
| (f) | \$ | 22 | \$ | 1,444 | \$ 52 \$ (1,234) \$ 284 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (c) | | 2 | 17 | - | (11) 8 |
| Interest Rate/Foreign Currency Hedges | | - | 5 | - | - 5 |
| Total Risk Management Liabilities | \$ | 24 | \$ | 1,466 | \$ 52 \$ (1,245) \$ 297 |

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Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2009

| | Level 1 | Level 2 | Level 3 (in millions) | Other | Total |
|---|----------|----------|--------------------------|------------|----------|
| Assets: | | | | | |
| Cash and Cash Equivalents (a) | \$ 427 | \$ - | \$ - | \$ 63 | \$ 490 |
| Other Temporary Investments | | | | | |
| Restricted Cash (a) | 198 | - | - | 25 | 223 |
| Fixed Income Securities: | | | | | |
| Mutual Funds | 57 | - | - | - | 57 |
| Variable Rate Demand Notes | - | 45 | - | - | 45 |
| Equity Securities (b): | | | | | |
| Domestic | 16 | - | - | - | 16 |
| Mutual Funds | 22 | - | - | - | 22 |
| Total Other Temporary Investments | 293 | 45 | - | 25 | 363 |
| Risk Management Assets | | | | | |
| Risk Management Commodity Contracts (c) | | | | | |
| (g) | 8 | 1,609 | 72 | (1,119) | 570 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (c) | 1 | 11 | - | (4) | 8 |
| Dedesignated Risk Management Contracts (d) | - | - | - | 25 | 25 |
| Total Risk Management Assets | 9 | 1,620 | 72 | (1,098) | 603 |
| Spent Nuclear Fuel and Decommissioning Trusts | | | | | |
| Cash and Cash Equivalents (e) | - | 3 | - | 11 | 14 |
| Fixed Income Securities: | | | | | |
| United States Government | - | 401 | - | - | 401 |
| Corporate Debt | - | 57 | - | - | 57 |
| State and Local Government | - | 369 | - | - | 369 |
| Subtotal Fixed Income Securities | - | 827 | - | - | 827 |
| Equity Securities - Domestic (b) | 551 | - | - | - | 551 |
| Total Spent Nuclear Fuel and Decommissioning Trusts | 551 | 830 | - | 11 | 1,392 |
| Total Assets | \$ 1,280 | \$ 2,495 | \$ 72 | \$ (999) | \$ 2,848 |
| Liabilities: | | | | | |
| Risk Management Liabilities | | | | | |
| Risk Management Commodity Contracts (c) | | | | | |
| (g) | \$ 11 | \$ 1,415 | \$ 10 | \$ (1,205) | \$ 231 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (c) | - | 16 | - | (4) | 12 |
| | - | 5 | - | - | 5 |

Interest Rate/Foreign Currency
Hedges

| | | | | | | | | | | |
|-----------------------------------|----|----|----|-------|----|----|----|---------|----|-----|
| Total Risk Management Liabilities | \$ | 11 | \$ | 1,436 | \$ | 10 | \$ | (1,209) | \$ | 248 |
|-----------------------------------|----|----|----|-------|----|----|----|---------|----|-----|

(a) Amounts in “Other” column primarily represent cash deposits in bank accounts with financial institutions or with third parties. Level 1 amounts primarily represent investments in money market funds. Level 2 amounts primarily represent investments in commercial paper.

(b) Amounts represent publicly traded equity securities and equity-based mutual funds.

(c) Amounts in “Other” column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for “Derivatives and Hedging.”

(d) Represents contracts that were originally MTM but were subsequently elected as normal under the accounting guidance for “Derivatives and Hedging.” At the time of the normal election, the MTM value was frozen and no longer fair valued. This MTM value will be amortized into revenues over the remaining life of the contracts.

(e) Amounts in “Other” column primarily represent accrued interest receivables from financial institutions. Level 2 amounts primarily represent investments in money market funds.

(f) The June 30, 2010 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures (\$1) million in 2010, (\$2) million in periods 2011-2013 and (\$2) million in periods 2014-2018; Level 2 matures \$43 million in 2010, \$69 million in periods 2011-2013, \$9 million in periods 2014-2015 and \$8 million in periods 2016-2028; Level 3 matures \$12 million in 2010, \$24 million in periods 2011-2013, \$22 million in periods 2014-2015 and \$42 million in periods 2016-2028. Risk management commodity contracts are substantially comprised of power contracts.

(g) The December 31, 2009 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures (\$1) million in 2010, (\$1) million in periods 2011-2013 and (\$1) million in periods 2014-2015; Level 2 matures \$65 million in 2010, \$84 million in periods 2011-2013, \$22 million in periods 2014-2015 and \$23 million in periods 2016-2028; Level 3 matures \$17 million in 2010, \$16 million in periods 2011-2013, \$8 million in periods 2014-2015 and \$21 million in periods 2016-2028.

There have been no transfers between Level 1 and Level 2 during the six months ended June 30, 2010.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives and other investments classified as Level 3 in the fair value hierarchy:

| Three Months Ended June 30, 2010 | | Net Risk Management Assets (Liabilities) (in millions) |
|--|----|--|
| Balance as of March 31, 2010 | \$ | 116 |
| Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b) | | (25) |
| Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) | | |
| Relating to Assets Still Held at the Reporting Date (a) | | 10 |
| Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income | | - |
| Purchases, Issuances and Settlements (c) | | 14 |
| Transfers into Level 3 (d) (h) | | 1 |
| Transfers out of Level 3 (e) (h) | | (6) |
| Changes in Fair Value Allocated to Regulated Jurisdictions (g) | | (10) |
| Balance as of June 30, 2010 | \$ | 100 |

| Six Months Ended June 30, 2010 | | Net Risk Management Assets (Liabilities) (in millions) |
|--|----|--|
| Balance as of December 31, 2009 | \$ | 62 |
| Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b) | | 4 |
| Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) | | |
| Relating to Assets Still Held at the Reporting Date (a) | | 33 |
| Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income | | - |
| Purchases, Issuances and Settlements (c) | | (13) |
| Transfers into Level 3 (d) (h) | | 12 |
| Transfers out of Level 3 (e) (h) | | (5) |
| Changes in Fair Value Allocated to Regulated Jurisdictions (g) | | 7 |
| Balance as of June 30, 2010 | \$ | 100 |

| | Net Risk Management Assets (Liabilities) (in millions) |
|---|--|
| Three Months Ended June 30, 2009 | |
| Balance as of March 31, 2009 | \$ 86 |
| Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a) | (15) |
| Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) | |
| Relating to Assets Still Held at the Reporting Date (a) | 7 |
| Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income | - |
| Purchases, Issuances and Settlements | - |
| Transfers in and/or out of Level 3 (f) | (29) |
| Changes in Fair Value Allocated to Regulated Jurisdictions (g) | 18 |
| Balance as of June 30, 2009 | \$ 67 |

| | Net Risk Management Assets (Liabilities) (in millions) |
|---|--|
| Six Months Ended June 30, 2009 | |
| Balance as of December 31, 2008 | \$ 49 |
| Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a) | (20) |
| Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) | |
| Relating to Assets Still Held at the Reporting Date (a) | 40 |
| Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income | - |
| Purchases, Issuances and Settlements | - |
| Transfers in and/or out of Level 3 (f) | (25) |
| Changes in Fair Value Allocated to Regulated Jurisdictions (g) | 23 |
| Balance as of June 30, 2009 | \$ 67 |

- (a) Included in revenues on our Condensed Consolidated Statements of Income.
- (b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
- (c) Represents the settlement of risk management commodity contracts for the reporting period.
- (d) Represents existing assets or liabilities that were previously categorized as Level 2.
- (e) Represents existing assets or liabilities that were previously categorized as Level 3.
- (f) Represents existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during the period.
- (g) Relates to the net gains (losses) of those contracts that are not reflected on our Condensed Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets.
- (h) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.

10. INCOME TAXES

We, along with our subsidiaries, file a consolidated federal income tax return. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The tax benefit of the Parent is allocated to our subsidiaries with taxable income. With the exception of the loss of the Parent, the method of allocation reflects a separate return result for each company in the consolidated group.

We are no longer subject to U.S. federal examination for years before 2001. We have completed the exam for the years 2001 through 2006 and have issues that we are pursuing at the appeals level. The years 2007 and 2008 are currently under examination. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. In addition, we accrue interest on these uncertain tax positions. We are not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on net income.

We, along with our subsidiaries, file income tax returns in various state, local and foreign jurisdictions. These taxing authorities routinely examine our tax returns and we are currently under examination in several state and local jurisdictions. We believe that we have filed tax returns with positions that may be challenged by these tax authorities. However, management believes that the ultimate resolution of these audits will not materially impact net income. With few exceptions, we are no longer subject to state, local or non-U.S. income tax examinations by tax authorities for years before 2000.

Federal Legislation

The Patient Protection and Affordable Care Act and the related Health Care and Education Reconciliation Act (Health Care Acts) were enacted in March 2010. The Health Care Acts amend tax rules so that the portion of employer health care costs that are reimbursed by the Medicare Part D prescription drug subsidy will no longer be deductible by the employer for federal income tax purposes effective for years beginning after December 31, 2012. Because of the loss of the future tax deduction, a reduction in the deferred tax asset related to the nondeductible OPEB liabilities accrued to date was recorded in March 2010. This reduction did not materially affect our cash flows or financial condition. For the six months ended June 30, 2010, deferred tax assets decreased \$56 million, partially offset by recording net tax regulatory assets of \$35 million in our jurisdictions with regulated operations, resulting in a decrease in net income of \$21 million.

11. FINANCING ACTIVITIES

Long-term Debt

| Type of Debt | June 30, 2010 | December 31, 2009 |
|-----------------------------------|---------------|-------------------|
| | (in millions) | |
| Senior Unsecured Notes | \$ 12,176 | \$ 12,416 |
| Pollution Control Bonds | 2,263 | 2,159 |
| Notes Payable | 376 | 326 |
| Securitization Bonds | 1,909 | 1,995 |
| Junior Subordinated Debentures | 315 | 315 |
| Spent Nuclear Fuel Obligation (a) | 265 | 265 |
| Other Long-term Debt | 88 | 88 |
| Unamortized Discount (net) | (44) | (66) |
| Total Long-term Debt | | |
| Outstanding | 17,348 | 17,498 |
| Less Portion Due Within One Year | 1,043 | 1,741 |
| Long-term Portion | \$ 16,305 | \$ 15,757 |

(a) Pursuant to the Nuclear Waste Policy Act of 1982, I&M (a nuclear licensee) has an obligation to the United States Department of Energy for spent nuclear fuel disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. Trust fund assets related to this obligation of \$307 million and \$306 million at June 30, 2010 and December 31, 2009, respectively, are included in Spent Nuclear Fuel and Decommissioning Trusts on our Condensed Consolidated Balance Sheets.

Long-term debt and other securities issued, retired and principal payments made during the first six months of 2010 are shown in the tables below.

| Company | Type of Debt | Principal Amount (in millions) | Interest Rate (%) | Due Date |
|-----------------|-------------------------|--------------------------------------|-------------------------|-------------|
| Issuances: | | | | |
| APCo | Senior Unsecured Notes | \$ 300 | 3.40 | 2015 |
| APCo | Pollution Control Bonds | 18 | 4.625 | 2021 |
| APCo | Pollution Control Bonds | 50 | 5.375 | 2038 |
| CSPCo | Floating Rate Notes | 150 | Variable | 2012 |
| I&M | Notes Payable | 84 | 4.00 | 2014 |
| OPCo | Pollution Control Bonds | 86 | 3.125 | 2015 |
| OPCo | Pollution Control Bonds | 79 | 3.25 | 2014 |
| SWEPCo | Senior Unsecured Notes | 350 | 6.20 | 2040 |
| SWEPCo | Pollution Control Bonds | 54 | 3.25 | 2015 |
| Total Issuances | | \$ 1,171 (a) | | |

The above borrowing arrangements do not contain guarantees, collateral or dividend restrictions.

(a) Amount indicated on the statement of cash flows of \$1,161 million is net of issuance costs and premium or discount.

| Company | Type of Debt | Principal Amount Paid (in millions) | Interest Rate (%) | Due Date |
|-------------------------------------|-------------------------|--|-------------------------|-------------|
| Retirements and Principal Payments: | | | | |
| AEP | Senior Unsecured Notes | \$ 490 | 5.375 | 2010 |
| APCo | Senior Unsecured Notes | 150 | 4.40 | 2010 |
| APCo | Pollution Control Bonds | 50 | 7.125 | 2010 |
| I&M | Notes Payable | 19 | 5.44 | 2013 |
| OPCo | Senior Unsecured Notes | 400 | Variable | 2010 |
| OPCo | | 79 | 7.125 | 2010 |

| | | | | |
|--|----------------------------|----|----------|------|
| | Pollution Control Bonds | | | |
| SWEPCo | Pollution Control Bonds | 54 | Variable | 2019 |
| Non-Registrant: | | | | |
| AEP Subsidiaries | Notes Payable | 4 | Variable | 2017 |
| AEP Subsidiaries | Notes Payable | 5 | Variable | 2011 |
| AEGCo | Senior Unsecured Notes | 4 | 6.33 | 2037 |
| TCC | Securitization Bonds | 32 | 5.56 | 2010 |
| TCC | Securitization Bonds | 54 | 4.98 | 2010 |
| Total Retirements and Principal Payments | | | | |
| | | \$ | 1,341 | |

As of June 30, 2010, trustees held, on our behalf, \$303 million of our reacquired auction-rate tax-exempt long-term debt.

Dividend Restrictions

The holders of our common stock are entitled to receive the dividends declared by our Board of Directors provided funds are legally available for such dividends. Our income derives from our common stock equity in the earnings of our utility subsidiaries. Various financing arrangements, charter provisions and regulatory requirements may impose certain restrictions on the ability of our utility subsidiaries to transfer funds to us in the form of dividends.

The Federal Power Act prohibits the utility subsidiaries from participating “in the making or paying of any dividends of such public utility from any funds properly included in capital account.” The term “capital account” is not defined in the Federal Power Act or its regulations. Management understands “capital account” to mean the par value of the common stock multiplied by the number of shares outstanding. This restriction does not limit the ability of the utility subsidiaries to pay dividends out of retained earnings.

We have issued \$315 million of Junior Subordinated Debentures. The debentures will mature on March 1, 2063, subject to extensions to no later than March 1, 2068. We have the option to defer interest payments on the debentures for one or more periods of up to 10 consecutive years per period. During any period in which we defer interest payments, we may not declare or pay any dividends or distributions on, or redeem, repurchase or acquire our common stock. We do not anticipate any deferral of those interest payments in the foreseeable future.

Pursuant to the leverage restrictions in our credit agreements, Parent and the Registrant Subsidiaries must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. The payment of cash dividends generally results in an increase in the percentage of debt to total capitalization of the company distributing the dividend. The method for calculating outstanding debt and other capital is contractually defined in the credit agreements. As of June 30, 2010, none of Parent’s retained earnings were restricted for the purpose of the payment of dividends. As of June 30, 2010, approximately \$204 million of the retained earnings of APCo, \$149 million of the retained earnings of CSPCo, \$33 million of the retained earnings of I&M, \$50 million of the retained earnings of OPCo, \$101 million of the retained earnings of SWEPCo and none of the retained earnings of PSO have restrictions related to the payment of dividends to Parent.

Short-term Debt

Our outstanding short-term debt was as follows:

| Type of Debt | June 30, 2010 | | | December 31, 2009 | |
|--|-------------------------------------|-------------------|---|-------------------------------------|-------------------|
| | Outstanding Amount (in millions) | Interest Rate (a) | | Outstanding Amount (in millions) | Interest Rate (a) |
| Securitized Debt for Receivables (b) | \$ 677 | 0.42 | % | \$ - | - |
| Commercial Paper | 787 | 0.51 | % | 119 | 0.26 % |
| Line of Credit – Sabine Mining Company (c) | 9 | 2.11 | % | 7 | 2.06 % |
| Total Short-term Debt | \$ 1,473 | | | \$ 126 | |

- (a) Weighted average rate.
- (b) Amount of securitized debt for receivables as accounted for under the “Transfers and Servicing” accounting guidance. See “ASU 2009-16 ‘Transfers and Servicing’ ” section of Note 2.
- (c) Sabine Mining Company is a consolidated variable interest entity. This line of credit does not reduce available liquidity under AEP’s credit facilities.

Credit Facilities

We have credit facilities totaling \$3 billion to support our commercial paper program. The facilities are structured as two \$1.5 billion credit facilities, of which \$750 million may be issued under one credit facility as letters of credit. In June 2010, we canceled a facility that was scheduled to mature in March 2011 and entered into a new \$1.5 billion credit facility scheduled to mature in 2013 that allows for the issuance of up to \$600 million as letters of credit. As of June 30, 2010, the maximum future payments for letters of credit issued under the two \$1.5 billion credit facilities were \$149 million.

In June 2010, we reduced the \$627 million credit agreement to \$478 million. Under the facility, we may issue letters of credit. As of June 30, 2010, \$477 million of letters of credit were issued by subsidiaries under this credit agreement to support variable rate Pollution Control Bonds.

Securitized Accounts Receivable – AEP Credit

AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from the bank conduits for the interest in the receivables it acquires from affiliated utility subsidiaries. Prior to January 1, 2010, this transaction constituted a sale of receivables in accordance with the accounting guidance for “Transfers and Servicing,” allowing the receivables to be removed from our Condensed Consolidated Balance Sheet. See “ASU 2009-16 ‘Transfers and Servicing’ ” section of Note 2 for discussion of impact of new accounting guidance effective January 1, 2010 whereby such future transactions do not constitute a sale of receivables and will be accounted for as financing. AEP Credit continues to service the receivables. We entered into these securitized transactions to allow AEP Credit to repay its outstanding debt obligations, continue to purchase our operating companies’ receivables and accelerate AEP Credit’s cash collections.

In July 2010, AEP Credit renewed its receivables securitization agreement. The agreement provides a commitment of \$750 million from bank conduits to finance receivables from AEP Credit. A commitment of \$375 million expires in July 2011 and the remaining commitment of \$375 million expires in July 2013.

Accounts receivable information for AEP Credit is as follows:

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|-----------------------------|----------|---------------------------|----------|
| | 2010 | 2009 | 2010 | 2009 |
| | (\$ in millions) | | | |
| Proceeds from Sale of Accounts Receivable | \$ N/A | \$ 2,061 | \$ N/A | \$ 4,249 |
| Loss on Sale of Accounts Receivable | N/A | 1 | N/A | 2 |
| Average Variable Discount Rate on Sale of Accounts Receivable | N/A | 0.55% | N/A | 0.83% |
| Effective Interest Rates on Securitization of Accounts Receivable | 0.31% | N/A | 0.27% | N/A |
| Net Uncollectible Accounts Receivable Written Off | 4 | 2 | 12 | 4 |

| | June 30, 2010 | December 31, 2009 |
|--|------------------|----------------------|
| | (in millions) | |
| Accounts Receivable Retained Interest and Pledged as Collateral | | |
| Less Uncollectible Accounts | \$ 983 | \$ 160 |
| Deferred Revenue from Servicing Accounts Receivable | N/A | 1 |
| Retained Interest if 10% Adverse Change in Uncollectible Accounts | N/A | 158 |
| Retained Interest if 20% Adverse Change in Uncollectible Accounts | N/A | 156 |
| Total Principal Outstanding | 677 | 656 |
| Derecognized Accounts Receivable | N/A | 631 |
| Delinquent Securitized Accounts Receivable | 42 | 29 |
| Bad Debt Reserves Related to Securitization/Sale of Accounts Receivable | 27 | 20 |
| Unbilled Receivables Related to Securitization/Sale of Accounts Receivable | 391 | 376 |

N/A = Not Applicable

Customer accounts receivable retained and securitized for our operating companies are managed by AEP Credit. AEP Credit's delinquent customer accounts receivable represents accounts greater than 30 days past due.

12.

COST REDUCTION INITIATIVES

In April 2010, we began initiatives to decrease both labor and non-labor expenses with a goal of achieving significant reductions in operation and maintenance expenses. Approximately 2,450 positions were eliminated as a result of process improvements, streamlined organizational designs and other efficiencies. Most of the affected employees terminated employment May 31, 2010. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

We recorded a charge to expense in the second quarter of 2010 primarily related to the headcount reduction initiatives.

| | Total (in millions) | |
|---------------------------------------|------------------------|-----|
| Incurred | \$ | 293 |
| Settled | | 4 |
| Remaining Balance at June 30, 2010 | \$ | 289 |

These costs relate primarily to severance benefits. They are included primarily in Other Operation on the income statement and Other Current Liabilities on the balance sheet. Approximately 99% of the expense was within the Utility Operations segment.

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

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APPALACHIAN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

RESULTS OF OPERATIONS

Second Quarter of 2010 Compared to Second Quarter of 2009

Reconciliation of Second Quarter of 2009 to Second Quarter of 2010
Net Income (Loss)
(in millions)

| | | | |
|---------------------------------|----|-----|---|
| Second Quarter of 2009 | \$ | 29 | |
| Changes in Gross Margin: | | | |
| Retail Margins | | 14 | |
| Transmission Revenues | | (1 |) |
| Other Revenues | | (2 |) |
| Total Change in Gross Margin | | 11 | |
| Total Expenses and Other: | | | |
| Other Operation and Maintenance | | (72 |) |
| Depreciation and Amortization | | (9 |) |
| Taxes Other Than Income Taxes | | (6 |) |
| Carrying Costs Income | | 5 | |
| Other Income | | (2 |) |
| Total Expenses and Other | | (84 |) |
| Income Tax Expense | | 24 | |
| Second Quarter of 2010 | \$ | (20 |) |

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins increased \$14 million primarily due to the following:
 - A \$22 million increase in rate relief primarily due to an increase in the recovery of E&R costs in Virginia, construction financing costs in West Virginia and costs related to the Transmission Rate Adjustment Clause in Virginia. This increase in retail margins had corresponding offsets of \$14 million related to cost recovery riders/trackers that were recognized in other expense line items below.
 - A \$5 million increase in residential usage primarily due to a 47% increase in cooling degree days.

These increases were partially offset by:

- An \$8 million decrease in non-weather related residential usage due to economic conditions.
- A \$3 million decrease in industrial sales primarily due to suspended operations in the first half of 2009 by APCo's largest customer, Century Aluminum.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses increased \$72 million primarily due to the following:
 - A \$55 million increase due to expenses related to the cost reduction initiatives in the second quarter of 2010.
 - A \$54 million increase due to the write-off of APCo's Virginia share of the Mountaineer Carbon Capture and Storage Project as denied for recovery by the Virginia SCC.
- These increases were partially offset by:
 - A \$25 million decrease due to the deferral of 2009 storm costs as allowed by the Virginia SCC.
 - A \$7 million decrease in maintenance expenses related to a true-up between expense and capital for the December 2009 storm.
 - A \$4 million decrease in employee-related expenses.
- Depreciation and Amortization expenses increased \$9 million primarily due to a greater depreciation base resulting from environmental upgrades at the Amos and Mountaineer Plants and the amortization of carrying charges and depreciation expenses being collected through the Virginia E&R surcharges.
- Taxes Other Than Income Taxes expense increased \$6 million primarily due to recording a West Virginia franchise tax audit settlement and additional employer payroll taxes incurred related to the cost reduction initiatives in the second quarter of 2010.
- Carrying Costs Income increased \$5 million primarily due to increased environmental deferrals in Virginia.
- Income Tax Expense decreased \$24 million primarily due to a decrease in pretax book income.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009

Reconciliation of Six Months Ended June 30, 2009 to Six Months Ended June 30, 2010

Net Income (Loss)

(in millions)

| | | |
|---------------------------------|----|-------|
| Six Months Ended June 30, 2009 | \$ | 104 |
| Changes in Gross Margin: | | |
| Retail Margins | | 56 |
| Off-system Sales | | 2 |
| Other Revenues | | (2) |
| Total Change in Gross Margin | | 56 |
| Total Expenses and Other: | | |
| Other Operation and Maintenance | | (104) |
| Depreciation and Amortization | | (16) |
| Taxes Other Than Income Taxes | | (8) |
| Carrying Costs Income | | 6 |
| Other Income | | (3) |
| Interest Expense | | (2) |
| Total Expenses and Other | | (127) |
| Income Tax Expense | | 18 |
| Six Months Ended June 30, 2010 | \$ | 51 |

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins increased \$56 million primarily due to the following:
 - A \$75 million increase in rate relief primarily due to the impact of the Virginia interim rate increase implemented in December 2009, subject to refund, and increases in the recoveries of E&R costs in Virginia, costs related to the Transmission Rate Adjustment Clause in Virginia and construction financing costs in West Virginia. This increase in retail margins had corresponding offsets of \$32 million related to cost recovery riders/trackers that were recognized in other expense line items below.
 - A \$17 million increase in residential usage primarily due to a 13% increase in heating degree days and a 42% increase in cooling degree days.
- These increases were partially offset by:
- A \$17 million decrease due to higher capacity settlement expenses under the Interconnection Agreement net of recovery in West Virginia and environmental deferrals in Virginia.
 - A \$14 million decrease in industrial sales primarily due to suspended operations in the first half of 2009 by APCo's largest customer, Century Aluminum.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses increased \$104 million primarily due to the following:
 - A \$55 million increase due to expenses related to the cost reduction initiatives in the second quarter of 2010.
 - A \$54 million increase due to the write-off of APCo's Virginia share of the Mountaineer Carbon Capture and Storage Project as denied for recovery by the Virginia SCC.
 - A \$10 million increase related to the reduction of a 2009 regulatory asset for the over-recovery of transmission costs.
 - A \$6 million increase in employee-related expenses.
 - A \$4 million increase related to generation plant maintenance.
- These increases were partially offset by:
 - A \$25 million decrease due to the deferral of 2009 storm costs as allowed by the Virginia SCC.
 - A \$7 million decrease in maintenance expenses related to a true-up between expense and capital related to the December 2009 storm.
- Depreciation and Amortization expenses increased \$16 million primarily due to a greater depreciation base resulting from environmental upgrades at the Amos and Mountaineer Plants and the amortization of carrying charges and depreciation expenses being collected through the Virginia E&R surcharges.
- Taxes Other Than Income Taxes expense increased \$8 million primarily due to recording a West Virginia franchise tax audit settlement and additional employer payroll taxes incurred related to the cost reduction initiatives in the second quarter of 2010.
- Carrying Costs Income increased \$6 million primarily due to increased environmental deferrals in Virginia.
- Income Tax Expense decreased \$18 million primarily due to a decrease in pretax book income, partially offset by the regulatory accounting treatment of state income taxes and other book/tax differences which are accounted for on a flow-through basis.

FINANCIAL CONDITION

LIQUIDITY

APCo participates in the Utility Money Pool, which provides access to AEP's liquidity. APCo relies upon ready access to capital markets, cash flows from operations and access to the Utility Money Pool to fund current operations and capital expenditures. See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page 224 for additional discussion of liquidity.

Credit Ratings

Downgrades in credit ratings by one of the rating agencies could increase APCo's borrowing costs.

CASH FLOW

Cash flows for the six months ended June 30, 2010 and 2009 were as follows:

| | 2010 | 2009 |
|--|----------------|-----------|
| | (in thousands) | |
| Cash and Cash Equivalents at Beginning of Period | \$ 2,006 | \$ 1,996 |
| | 252,172 | (90,383) |

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Net Cash Flows from (Used for) Operating
Activities

| | | |
|--|------------|------------|
| Net Cash Flows Used for Investing Activities | (252,171) | (313,971) |
|--|------------|------------|

Net Cash Flows from (Used for) Financing
Activities

| | |
|--------|---------|
| (181) | 404,159 |
|--------|---------|

| | | |
|---|--------|--------|
| Net Decrease in Cash and Cash Equivalents | (180) | (195) |
|---|--------|--------|

| | | |
|--|----------|----------|
| Cash and Cash Equivalents at End of Period | \$ 1,826 | \$ 1,801 |
|--|----------|----------|

Operating Activities

Net Cash Flows from Operating Activities were \$252 million in 2010. APCo produced Net Income of \$51 million during the period and noncash expense items of \$151 million for Depreciation and Amortization and \$32 million for Deferred Income Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The \$100 million outflow from Accounts Payable was primarily due to the placement of FGD equipment into service at the Amos Plant and decreased purchases of energy from the system pool. The \$76 million inflow from Accounts Receivable, Net was primarily due to a decrease in accrued unbilled revenues due to usual seasonal fluctuations and timing of settlements of receivables from affiliated companies. The \$69 million inflow from Fuel, Materials and Supplies was primarily due to a reduction in fuel inventory and a decrease in the average cost per ton. The \$39 million outflow from Accrued Taxes, Net was primarily due to increased accruals related to federal income taxes. The \$32 million outflow from Fuel Over/Under-Recovery, Net was primarily due to a net under-recovery of fuel costs in West Virginia.

Net Cash Flows Used for Operating Activities were \$90 million in 2009. APCo produced Net Income of \$104 million during the period and had noncash expense items of \$135 million for Deferred Income Taxes and \$134 million for Depreciation and Amortization. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The \$136 million cash outflow from Accounts Payable was primarily due to APCo's provision for revenue refund of \$77 million which was paid in the first quarter of 2009 to the AEP West companies as part of a FERC order on the SIA. The \$93 million outflow from Fuel, Materials and Supplies was primarily due to an increase in coal inventory. The \$87 million inflow from Accounts Receivable, Net was primarily due to a decrease in accrued unbilled revenues due to usual seasonal fluctuations and timing of settlements of receivables from affiliated companies. The \$79 million outflow from Accrued Taxes, Net was primarily due to increased accruals related to federal income taxes. The \$138 million outflow from Fuel Over/Under-Recovery, Net was primarily due to a net under-recovery of fuel costs in both Virginia and West Virginia.

Investing Activities

Net Cash Flows Used for Investing Activities during 2010 and 2009 were \$252 million and \$314 million, respectively. Construction Expenditures of \$255 million and \$328 million in 2010 and 2009, respectively, were primarily for projects to improve service reliability for transmission and distribution, as well as environmental upgrades. Environmental upgrades primarily include the installation of FGD equipment at the Amos Plant.

Financing Activities

Net Cash Flows Used for Financing Activities were \$181 thousand in 2010. APCo issued \$300 million of Senior Unsecured Notes and \$68 million of Pollution Control Bonds. APCo had a net increase of \$17 million in borrowings from the Utility Money Pool. These increases were partially offset by the retirement of \$150 million of Senior Unsecured Notes, \$100 million of Notes Payable – Affiliated and \$50 million of Pollution Control Bonds. In addition, APCo paid \$78 million in dividends on common stock.

Net Cash Flows from Financing Activities were \$404 million in 2009. APCo received capital contributions from the Parent of \$250 million in the second quarter of 2009. APCo issued \$350 million of Senior Unsecured Notes and retired \$150 million of Senior Unsecured Notes.

Long-term debt issuances, retirements and principal payments made during the first six months of 2010 were:

Issuances

| Type of Debt | Principal Amount (in thousands) | Interest Rate (%) | Due Date |
|-------------------------|------------------------------------|----------------------|----------|
| Pollution Control Bonds | \$ 17,500 | 4.625 | 2021 |
| Pollution Control Bonds | 50,000 | 5.375 | 2038 |
| Senior Unsecured Notes | 300,000 | 3.40 | 2015 |

Retirements and Principal Payments

| Type of Debt | Principal Amount Paid (in thousands) | Interest Rate (%) | Due Date |
|----------------------------|---|----------------------|----------|
| Notes Payable – Affiliated | \$ 100,000 | 4.708 | 2010 |
| Senior Unsecured Notes | 150,000 | 4.40 | 2010 |
| Pollution Control Bonds | 50,000 | 7.125 | 2010 |
| Land Note | 9 | 13.718 | 2026 |

SUMMARY OBLIGATION INFORMATION

A summary of contractual obligations is included in the 2009 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in “Cash Flow” above.

REGULATORY ACTIVITY

Virginia Regulatory Activity

In July 2009, APCo filed a generation and distribution base rate increase with the Virginia SCC of \$154 million annually based on a 13.35% return on common equity. Interim rates, subject to refund, became effective in December 2009 but were discontinued in February 2010 when Virginia newly enacted legislation suspended the collection of interim rates. In July 2010, the Virginia SCC issued an order approving a \$62 million increase based on a 10.53% return on equity. The order denied recovery of the Virginia share of the Mountaineer Carbon Capture and Storage Project, which resulted in a write-off of approximately \$54 million in the second quarter of 2010. In addition, the order allowed the deferral in the second quarter of 2010 of approximately \$25 million of incremental storm expense incurred in 2009. In July 2010, APCo filed with the Virginia SCC a petition for reconsideration of the order as it relates to the Mountaineer Carbon Capture and Storage Project. See “2009 Virginia Base Rate Case” section of Note 3.

In June 2010, the Virginia SCC denied APCo’s request to include certain wind purchased power agreements (Beech Ridge and Grand Ridge) with a 20-year term in its Virginia renewable energy portfolio standard program. As a result, APCo recorded an expense of \$4 million in June 2010 to reduce the regulatory asset related to the Virginia portion of wind power costs to reflect the difference between the actual Grand Ridge purchased power costs incurred from September 2009 through June 2010 and the cost of non-wind power. No costs to date have been deferred for Beech Ridge, which is estimated to be in service in the third quarter of 2010. Management is evaluating several options

regarding the Beech Ridge and Grand Ridge contracts. APCo's future net income and cash flows will be reduced by the unrecoverable Virginia portion of the Beech Ridge and Grand Ridge costs until such time as the contracts are reassigned, renegotiated or terminated.

West Virginia Regulatory Activity

In May 2010, APCo filed a request with the WVPSC to increase annual base rates by \$140 million based on an 11.75% return on common equity to be effective March 2011. Hearings are scheduled for December 2010. A decision from the WVPSC is expected in March 2011. See “2010 West Virginia Base Rate Case” section of Note 3.

In a proceeding established by the WVPSC to explore options to meet WPCo's future power supply requirements, the WVPSC, in November 2009, issued an order approving a joint stipulation among APCo, WPCo, the WVPSC staff and the Consumer Advocate Division. The order approved the recommendation of the signatories to the stipulation that WPCo merge into APCo and be supplied from APCo's existing power resources. Merger approvals from the WVPSC, Virginia SCC and the FERC are required. No merger approval filings have been made. See “WPCo Merger with APCo” section of Note 3.

SIGNIFICANT FACTORS

REGULATORY ISSUES

Mountaineer Carbon Capture and Storage Project

APCo and ALSTOM Power, Inc. (Alstom), an unrelated third party, jointly constructed a CO₂ capture validation facility, which was placed into service in September 2009. APCo also constructed and owns the necessary facilities to store the CO₂. In APCo's July 2009 Virginia base rate filing and May 2010 West Virginia base rate filing, APCo requested recovery of and a return on its estimated increased Virginia and West Virginia jurisdictional share of its project costs and recovery of the related asset retirement obligation regulatory asset amortization and accretion. In July 2010, the Virginia SCC issued a base rate order that denied recovery of the Virginia share of the Mountaineer Carbon Capture and Storage Project costs, which resulted in a pretax write-off of approximately \$54 million in the second quarter of 2010. In response to the order, APCo filed with the Virginia SCC a petition for reconsideration of the order as it relates to the Mountaineer Carbon Capture and Storage Project. Through June 30, 2010, APCo has recorded a noncurrent regulatory asset of \$58 million consisting of \$38 million in project costs and \$20 million in asset retirement costs. If APCo cannot recover its remaining investments in and expenses related to the Mountaineer Carbon Capture and Storage project, it would reduce future net income and cash flows and impact financial condition. See “Mountaineer Carbon Capture and Storage Project” section of Note 3.

LITIGATION AND ENVIRONMENTAL ISSUES

In the ordinary course of business, APCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual resolution will be or the timing and amount of any loss, fine or penalty may be. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2009 Annual Report. Also, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 156. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

See the “Significant Factors” section of “Combined Management's Discussion and Analysis of Registrant Subsidiaries” section beginning on page 224 for additional discussion of relevant factors.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the “Critical Accounting Policies and Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” in the 2009 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets and pension and other postretirement benefits.

See the “New Accounting Pronouncements” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” beginning on page 224 for a discussion of the adoption and impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

See “Quantitative And Qualitative Disclosures About Risk Management Activities” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” beginning on page 224 for a discussion of risk management activities.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

For the Three and Six Months Ended June 30, 2010 and 2009

(in thousands)

(Unaudited)

| | Three Months Ended | | Six Months Ended | |
|---|--------------------|-----------------|------------------|------------------|
| | 2010 | 2009 | 2010 | 2009 |
| REVENUES | | | | |
| Electric Generation, Transmission and Distribution | \$633,140 | \$572,027 | \$1,479,130 | \$1,299,986 |
| Sales to AEP Affiliates | 67,365 | 62,038 | 146,136 | 118,269 |
| Other Revenues | 2,769 | 2,047 | 4,631 | 3,886 |
| TOTAL REVENUES | 703,274 | 636,112 | 1,629,897 | 1,422,141 |
| EXPENSES | | | | |
| Fuel and Other Consumables Used for Electric Generation | 169,616 | 118,891 | 350,256 | 262,572 |
| Purchased Electricity for Resale | 56,936 | 59,631 | 120,619 | 135,447 |
| Purchased Electricity from AEP Affiliates | 179,607 | 171,064 | 447,109 | 368,188 |
| Other Operation | 170,907 | 63,537 | 260,947 | 129,039 |
| Maintenance | 14,060 | 49,478 | 77,170 | 105,388 |
| Depreciation and Amortization | 73,160 | 64,148 | 150,590 | 134,143 |
| Taxes Other Than Income Taxes | 29,955 | 23,796 | 56,235 | 47,899 |
| TOTAL EXPENSES | 694,241 | 550,545 | 1,462,926 | 1,182,676 |
| OPERATING INCOME | 9,033 | 85,567 | 166,971 | 239,465 |
| Other Income (Expense): | | | | |
| Interest Income | 662 | 395 | 953 | 777 |
| Carrying Costs Income | 10,298 | 5,791 | 16,062 | 9,874 |
| Allowance for Equity Funds Used During Construction | 128 | 1,184 | 1,291 | 3,837 |
| Interest Expense | (51,831) | (51,457) | (103,558) | (101,162) |
| INCOME (LOSS) BEFORE INCOME TAX EXPENSE (CREDIT) | (31,710) | 41,480 | 81,719 | 152,791 |
| Income Tax Expense (Credit) | (12,091) | 12,310 | 31,056 | 49,214 |
| NET INCOME (LOSS) | (19,619) | 29,170 | 50,663 | 103,577 |
| Preferred Stock Dividend Requirements Including Capital Stock Expense | | | | |
| | 225 | 225 | 450 | 450 |
| EARNINGS (LOSS) ATTRIBUTABLE TO COMMON STOCK | \$(19,844) | \$28,945 | \$50,213 | \$103,127 |

The common stock of APCo is wholly-owned by AEP.

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME (LOSS)

For the Six Months Ended June 30, 2010 and 2009

(in thousands)

(Unaudited)

| | Common Stock | Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
|--|-----------------|--------------------|----------------------|--|-------------|
| TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2008 | \$260,458 | \$1,225,292 | \$951,066 | \$ (60,225) | \$2,376,591 |
| Capital Contribution from Parent | | 250,000 | | | 250,000 |
| Common Stock Dividends | | | (20,000) | | (20,000) |
| Preferred Stock Dividends | | | (399) | | (399) |
| Capital Stock Expense | | 51 | (51) | | - |
| SUBTOTAL – COMMON SHAREHOLDER'S EQUITY | | | | | 2,606,192 |
| COMPREHENSIVE INCOME | | | | | |
| Other Comprehensive Income, Net of Taxes: | | | | | |
| Cash Flow Hedges, Net of Tax of \$217 | | | | 403 | 403 |
| Amortization of Pension and OPEB Deferred | | | | | |
| Costs, Net of Tax of \$1,034 | | | | 1,920 | 1,920 |
| NET INCOME | | | 103,577 | | 103,577 |
| TOTAL COMPREHENSIVE INCOME | | | | | 105,900 |
| TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2009 | \$260,458 | \$1,475,343 | \$1,034,193 | \$ (57,902) | \$2,712,092 |
| TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2009 | \$260,458 | \$1,475,393 | \$1,085,980 | \$ (50,254) | \$2,771,577 |
| Common Stock Dividends | | | (78,000) | | (78,000) |
| Preferred Stock Dividends | | | (399) | | (399) |
| Capital Stock Expense | | 52 | (51) | | 1 |
| SUBTOTAL – COMMON SHAREHOLDER'S EQUITY | | | | | 2,693,179 |
| COMPREHENSIVE INCOME | | | | | |
| Other Comprehensive Income (Loss), Net of Taxes: | | | | | |
| Cash Flow Hedges, Net of Tax of \$1,369 | | | | (2,542) | (2,542) |

Amortization of Pension and OPEB

Deferred

| | | | |
|------------------------------|--------|-------|--------|
| Costs, Net of Tax of \$1,124 | | 2,087 | 2,087 |
| NET INCOME | 50,663 | | 50,663 |
| TOTAL COMPREHENSIVE INCOME | | | 50,208 |

TOTAL COMMON SHAREHOLDER'S

| | | | | | |
|------------------------|-----------|-------------|-------------|--------------|-------------|
| EQUITY – JUNE 30, 2010 | \$260,458 | \$1,475,445 | \$1,058,193 | \$ (50,709) | \$2,743,387 |
|------------------------|-----------|-------------|-------------|--------------|-------------|

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS

ASSETS

June 30, 2010 and December 31, 2009

(in thousands)

(Unaudited)

| | 2010 | 2009 |
|--|--------------------|--------------------|
| CURRENT ASSETS | | |
| Cash and Cash Equivalents | \$1,826 | \$2,006 |
| Accounts Receivable: | | |
| Customers | 160,841 | 150,285 |
| Affiliated Companies | 66,933 | 135,686 |
| Accrued Unbilled Revenues | 54,265 | 68,971 |
| Miscellaneous | 4,052 | 6,690 |
| Allowance for Uncollectible Accounts | (5,770) | (5,408) |
| Total Accounts Receivable | 280,321 | 356,224 |
| Fuel | 272,147 | 343,261 |
| Materials and Supplies | 90,220 | 88,575 |
| Risk Management Assets | 54,819 | 67,956 |
| Accrued Tax Benefits | 213,891 | 180,708 |
| Regulatory Asset for Under-Recovered Fuel Costs | 36,652 | 78,685 |
| Prepayments and Other Current Assets | 30,419 | 36,293 |
| TOTAL CURRENT ASSETS | 980,295 | 1,153,708 |
| PROPERTY, PLANT AND EQUIPMENT | | |
| Electric: | | |
| Production | 4,632,273 | 4,284,361 |
| Transmission | 1,830,336 | 1,813,777 |
| Distribution | 2,686,675 | 2,642,479 |
| Other Property, Plant and Equipment | 361,450 | 329,497 |
| Construction Work in Progress | 450,005 | 730,099 |
| Total Property, Plant and Equipment | 9,960,739 | 9,800,213 |
| Accumulated Depreciation and Amortization | 2,808,993 | 2,751,443 |
| TOTAL PROPERTY, PLANT AND EQUIPMENT – NET | 7,151,746 | 7,048,770 |
| OTHER NONCURRENT ASSETS | | |
| Regulatory Assets | 1,467,502 | 1,433,791 |
| Long-term Risk Management Assets | 48,088 | 47,141 |
| Deferred Charges and Other Noncurrent Assets | 121,172 | 113,003 |
| TOTAL OTHER NONCURRENT ASSETS | 1,636,762 | 1,593,935 |
| TOTAL ASSETS | \$9,768,803 | \$9,796,413 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY

June 30, 2010 and December 31, 2009

(Unaudited)

| | 2010 | 2009 |
|--|----------------|-------------|
| | (in thousands) | |
| CURRENT LIABILITIES | | |
| Advances from Affiliates | \$246,873 | \$229,546 |
| Accounts Payable: | | |
| General | 156,418 | 291,240 |
| Affiliated Companies | 127,104 | 157,640 |
| Long-term Debt Due Within One Year – Nonaffiliated | 250,020 | 200,019 |
| Long-term Debt Due Within One Year – Affiliated | - | 100,000 |
| Risk Management Liabilities | 24,839 | 25,792 |
| Customer Deposits | 58,144 | 57,578 |
| Deferred Income Taxes | 56,364 | 68,706 |
| Accrued Taxes | 59,924 | 65,241 |
| Accrued Interest | 57,673 | 58,962 |
| Other Current Liabilities | 112,244 | 95,292 |
| TOTAL CURRENT LIABILITIES | 1,149,603 | 1,350,016 |
| NONCURRENT LIABILITIES | | |
| Long-term Debt – Nonaffiliated | 3,310,756 | 3,177,287 |
| Long-term Risk Management Liabilities | 19,744 | 20,364 |
| Deferred Income Taxes | 1,500,176 | 1,439,884 |
| Regulatory Liabilities and Deferred Investment Tax Credits | 544,263 | 526,546 |
| Employee Benefits and Pension Obligations | 303,680 | 312,873 |
| Deferred Credits and Other Noncurrent Liabilities | 179,447 | 180,114 |
| TOTAL NONCURRENT LIABILITIES | 5,858,066 | 5,657,068 |
| TOTAL LIABILITIES | 7,007,669 | 7,007,084 |
| Cumulative Preferred Stock Not Subject to Mandatory Redemption | 17,747 | 17,752 |
| Rate Matters (Note 3) | | |
| Commitments and Contingencies (Note 4) | | |
| COMMON SHAREHOLDER’S EQUITY | | |
| Common Stock – No Par Value: | | |
| Authorized – 30,000,000 Shares | | |
| Outstanding – 13,499,500 Shares | 260,458 | 260,458 |
| Paid-in Capital | 1,475,445 | 1,475,393 |
| Retained Earnings | 1,058,193 | 1,085,980 |
| Accumulated Other Comprehensive Income (Loss) | (50,709) | (50,254) |
| TOTAL COMMON SHAREHOLDER’S EQUITY | 2,743,387 | 2,771,577 |
| TOTAL LIABILITIES AND SHAREHOLDERS’ EQUITY | \$9,768,803 | \$9,796,413 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Six Months Ended June 30, 2010 and 2009

(in thousands)

(Unaudited)

| | 2010 | 2009 |
|---|------------|------------|
| OPERATING ACTIVITIES | | |
| Net Income | \$50,663 | \$103,577 |
| Adjustments to Reconcile Net Income to Net Cash Flows from (Used for) | | |
| Operating Activities: | | |
| Depreciation and Amortization | 150,590 | 134,143 |
| Deferred Income Taxes | 32,037 | 135,034 |
| Carrying Costs Income | (16,062) | (9,874) |
| Allowance for Equity Funds Used During Construction | (1,291) | (3,837) |
| Mark-to-Market of Risk Management Contracts | 9,975 | (23,490) |
| Fuel Over/Under-Recovery, Net | (32,329) | (137,717) |
| Change in Other Noncurrent Assets | 42,141 | (24,202) |
| Change in Other Noncurrent Liabilities | (5,225) | 13,786 |
| Changes in Certain Components of Working Capital: | | |
| Accounts Receivable, Net | 75,903 | 86,840 |
| Fuel, Materials and Supplies | 69,469 | (93,304) |
| Accounts Payable | (100,171) | (136,330) |
| Accrued Taxes, Net | (38,806) | (78,773) |
| Other Current Assets | 5,421 | (29,341) |
| Other Current Liabilities | 9,857 | (26,895) |
| Net Cash Flows from (Used for) Operating Activities | 252,172 | (90,383) |
| INVESTING ACTIVITIES | | |
| Construction Expenditures | (254,663) | (327,982) |
| Other Investing Activities | 2,492 | 14,011 |
| Net Cash Flows Used for Investing Activities | (252,171) | (313,971) |
| FINANCING ACTIVITIES | | |
| Capital Contribution from Parent | - | 250,000 |
| Issuance of Long-term Debt – Nonaffiliated | 363,913 | 345,666 |
| Change in Advances from Affiliates, Net | 17,327 | (19,512) |
| Retirement of Long-term Debt – Nonaffiliated | (200,009) | (150,008) |
| Retirement of Long-term Debt – Affiliated | (100,000) | - |
| Retirement of Cumulative Preferred Stock | (4) | - |
| Principal Payments for Capital Lease Obligations | (3,600) | (1,669) |
| Dividends Paid on Common Stock | (78,000) | (20,000) |
| Dividends Paid on Cumulative Preferred Stock | (399) | (399) |
| Other Financing Activities | 591 | 81 |
| Net Cash Flows from (Used for) Financing Activities | (181) | 404,159 |
| Net Decrease in Cash and Cash Equivalents | (180) | (195) |
| Cash and Cash Equivalents at Beginning of Period | 2,006 | 1,996 |
| Cash and Cash Equivalents at End of Period | \$1,826 | \$1,801 |

SUPPLEMENTARY INFORMATION

| | | |
|--|-----------|-----------|
| Cash Paid for Interest, Net of Capitalized Amounts | \$103,271 | \$114,983 |
| Net Cash Paid (Received) for Income Taxes | 30,259 | (2,644) |
| Noncash Acquisitions Under Capital Leases | 22,344 | 526 |
| Construction Expenditures Included in Accounts Payable at June 30, | 42,890 | 69,300 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF
REGISTRANT SUBSIDIARIES

The condensed notes to APCo's condensed consolidated financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to APCo. The footnotes begin on page 156.

| | Footnote Reference |
|--|-----------------------|
| Significant Accounting Matters | Note 1 |
| New Accounting Pronouncements and Extraordinary Item | Note 2 |
| Rate Matters | Note 3 |
| Commitments, Guarantees and Contingencies | Note 4 |
| Benefit Plans | Note 6 |
| Business Segments | Note 7 |
| Derivatives and Hedging | Note 8 |
| Fair Value Measurements | Note 9 |
| Income Taxes | Note 10 |
| Financing Activities | Note 11 |
| Cost Reduction Initiatives | Note 12 |

COLUMBUS SOUTHERN POWER COMPANY
AND SUBSIDIARIES

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COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

RESULTS OF OPERATIONS

Second Quarter of 2010 Compared to Second Quarter of 2009

Reconciliation of Second Quarter of 2009 to Second Quarter of 2010

Net Income

(in millions)

| | | |
|---------------------------------|-----|----|
| Second Quarter of 2009 | \$ | 84 |
| Changes in Gross Margin: | | |
| Retail Margins | (15 |) |
| Off-system Sales | (3 |) |
| Total Change in Gross Margin | (18 |) |
| Total Expenses and Other: | | |
| Other Operation and Maintenance | (32 |) |
| Depreciation and Amortization | (3 |) |
| Taxes Other Than Income Taxes | (1 |) |
| Total Expenses and Other | (36 |) |
| Income Tax Expense | | 22 |
| Second Quarter of 2010 | \$ | 52 |

The major components of the decrease in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins decreased \$15 million due to:
 - A \$14 million decrease as a result of the timing of the approval and implementation of new rates set by the Ohio ESP from April through December 2009.
 - An \$8 million decrease in fuel margins.
 - An \$8 million decrease in capacity settlements under the Interconnection Agreement.
 - A \$4 million decrease as a result of the loss of the City of Westerville as a dedicated customer to Off-system Sales. These sales are shared by the members of the AEP Power Pool.

These decreases were partially offset by:

- A \$13 million increase in residential and commercial revenue, \$8 million of which was due to weather-related usage and a 33% increase in cooling degree days.
- Margins from Off-system Sales decreased \$3 million primarily due to lower trading and marketing margins, partially offset by higher physical sales volumes.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses increased \$32 million primarily due to:
 - A \$31 million increase due to expenses incurred related to the cost reduction initiatives in the second quarter of 2010.
 - A \$3 million increase in recoverable customer account expenses due to increased Universal Service Fund surcharge rates for customers who qualify for payment assistance.
- These increases were partially offset by:
- A \$6 million decrease in boiler plant maintenance expenses primarily related to work performed at the Conesville and Zimmer plants in 2009.
 - Depreciation and Amortization increased \$3 million primarily due to projects at the Conesville Plant that were completed and placed in service in November 2009.
 - Income Tax Expense decreased \$22 million primarily due to a decrease in pretax book income.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009

Reconciliation of Six Months Ended June 30, 2009 to Six Months Ended June 30, 2010

Net Income
(in millions)

| | | |
|---------------------------------|----|------|
| Six Months Ended June 30, 2009 | \$ | 133 |
| Changes in Gross Margin: | | |
| Retail Margins | | (12) |
| Off-system Sales | | 1 |
| Other | | (1) |
| Total Change in Gross Margin | | (12) |
| Total Expenses and Other: | | |
| Other Operation and Maintenance | | (26) |
| Depreciation and Amortization | | (5) |
| Taxes Other Than Income Taxes | | (3) |
| Interest Expense | | (1) |
| Total Expenses and Other | | (35) |
| Income Tax Expense | | 18 |
| Six Months Ended June 30, 2010 | \$ | 104 |

The major component of the decrease in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power was as follows:

- Retail Margins decreased \$12 million due to:
 - A \$14 million decrease as a result of the elimination of Restructuring Transition Charge (RTC) revenues with the implementation of CSPCo's ESP.
 - An \$11 million decrease in capacity settlements under the Interconnection Agreement.
 - An \$8 million decrease as a result of the loss of the City of Westerville as a dedicated customer to Off-system Sales. These sales are shared by the members of the AEP Power Pool.
- These decreases were partially offset by:
 - A \$9 million increase in retail sales attributable to residential and commercial classes due to weather-related usage and a 32% increase in cooling degree days.
 - An \$8 million increase related to the implementation of higher rates set by the Ohio ESP.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses increased \$26 million primarily due to:
 - A \$31 million increase due to expenses incurred related to the cost reduction initiatives in the second quarter of 2010.

- A \$6 million increase in recoverable customer account expenses due to increased Universal Service Fund surcharge rates for customers who qualify for payment assistance.

These increases were partially offset by:

- A \$7 million decrease related to a 2009 obligation to contribute to the “Partnership with Ohio” fund for low income, at-risk customers ordered by the PUCO’s March 2009 approval of CSPCo’s ESP.
- A \$7 million decrease in boiler plant maintenance expenses primarily related to work performed at the Conesville and Zimmer plants.
- Depreciation and Amortization increased \$5 million primarily due to projects at the Conesville Plant that were completed and placed in service in November 2009.
- Income Tax Expense decreased \$18 million primarily due to a decrease in pretax book income.

SIGNIFICANT FACTORS

REGULATORY ISSUES

Ohio Electric Security Plan Filing

During 2009, the PUCO issued an order that modified and approved CSPCo's ESP which established rates through 2011. The order also limits rate increases for CSPCo to 7% in 2009, 6% in 2010 and 6% in 2011. The order provides a FAC for the three-year period of the ESP. Several notices of appeal are outstanding at the Supreme Court of Ohio relating to significant issues in the determination of the approved ESP rates. CSPCo will file its significantly excessive earnings test with the PUCO by the September 2010 deadline. CSPCo is unable to determine whether it will be required to return any of the ESP revenues to customers. See "Ohio Electric Security Plan Filings" section of Note 3.

LITIGATION AND ENVIRONMENTAL ISSUES

In the ordinary course of business, CSPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual resolution will be or the timing and amount of any loss, fine or penalty may be. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2009 Annual Report. Also, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 156. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

See the "Significant Factors" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page 224 for additional discussion of relevant factors.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the "Critical Accounting Policies and Estimates" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2009 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets and pension and other postretirement benefits.

See the "New Accounting Pronouncements" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" beginning on page 224 for a discussion of the adoption and impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

See "Quantitative And Qualitative Disclosures About Risk Management Activities" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" beginning on page 224 for a discussion of risk management activities.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

For the Three and Six Months Ended June 30, 2010 and 2009

(in thousands)

(Unaudited)

| | Three Months Ended | | Six Months Ended | |
|---|--------------------|-----------------|------------------|------------------|
| | 2010 | 2009 | 2010 | 2009 |
| REVENUES | | | | |
| Electric Generation, Transmission and Distribution | \$503,270 | \$488,193 | \$1,004,289 | \$949,115 |
| Sales to AEP Affiliates | 20,090 | 19,165 | 35,922 | 29,371 |
| Other Revenues | 744 | 518 | 1,332 | 1,126 |
| TOTAL REVENUES | 524,104 | 507,876 | 1,041,543 | 979,612 |
| EXPENSES | | | | |
| Fuel and Other Consumables Used for Electric Generation | 105,290 | 63,476 | 219,731 | 134,420 |
| Purchased Electricity for Resale | 20,138 | 22,422 | 39,783 | 52,260 |
| Purchased Electricity from AEP Affiliates | 91,287 | 96,068 | 190,086 | 189,160 |
| Other Operation | 103,229 | 65,555 | 180,555 | 141,643 |
| Maintenance | 25,114 | 31,618 | 49,397 | 62,632 |
| Depreciation and Amortization | 37,602 | 34,626 | 75,089 | 69,571 |
| Taxes Other Than Income Taxes | 44,294 | 43,145 | 91,351 | 88,427 |
| TOTAL EXPENSES | 426,954 | 356,910 | 845,992 | 738,113 |
| OPERATING INCOME | 97,150 | 150,966 | 195,551 | 241,499 |
| Other Income (Expense): | | | | |
| Interest Income | 167 | 234 | 309 | 474 |
| Carrying Costs Income | 1,963 | 1,721 | 4,184 | 3,410 |
| Allowance for Equity Funds Used During Construction | 314 | 585 | 1,235 | 1,885 |
| Interest Expense | (21,091) | (21,076) | (42,875) | (41,869) |
| INCOME BEFORE INCOME TAX EXPENSE | 78,503 | 132,430 | 158,404 | 205,399 |
| Income Tax Expense | 26,387 | 48,252 | 54,638 | 72,363 |
| NET INCOME | 52,116 | 84,178 | 103,766 | 133,036 |
| Capital Stock Expense | 40 | 40 | 79 | 79 |
| EARNINGS ATTRIBUTABLE TO COMMON STOCK | \$52,076 | \$84,138 | \$103,687 | \$132,957 |

The common stock of CSPCo is wholly-owned by AEP.

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME (LOSS)

For the Six Months Ended June 30, 2010 and 2009

(in thousands)

(Unaudited)

| | Common Stock | Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
|--|-----------------|--------------------|----------------------|--|-------------|
| TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2008 | \$41,026 | \$580,506 | \$674,758 | \$ (51,025) | \$1,245,265 |
| Common Stock Dividends | | | (100,000) | | (100,000) |
| Capital Stock Expense | | 79 | (79) | | - |
| Noncash Dividend of Property to Parent | | | (8,123) | | (8,123) |
| SUBTOTAL – COMMON SHAREHOLDER'S EQUITY | | | | | 1,137,142 |

COMPREHENSIVE INCOME

Other Comprehensive Income (Loss), Net
of

Taxes:

Cash Flow Hedges, Net of Tax of \$184 (342) (342)

Amortization of Pension and OPEB

Deferred

Costs, Net of Tax of \$514 954 954

NET INCOME 133,036 133,036

TOTAL COMPREHENSIVE INCOME 133,648

| | | | | | |
|--|----------|-----------|-----------|--------------|-------------|
| TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2009 | \$41,026 | \$580,585 | \$699,592 | \$ (50,413) | \$1,270,790 |
|--|----------|-----------|-----------|--------------|-------------|

| | | | | | |
|--|----------|-----------|-----------|--------------|-------------|
| TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2009 | \$41,026 | \$580,663 | \$788,139 | \$ (49,993) | \$1,359,835 |
|--|----------|-----------|-----------|--------------|-------------|

| | | | | | |
|------------------------|--|--|-----------|--|-----------|
| Common Stock Dividends | | | (52,500) | | (52,500) |
|------------------------|--|--|-----------|--|-----------|

| | | | | | |
|-----------------------|--|----|-------|--|---|
| Capital Stock Expense | | 79 | (79) | | - |
|-----------------------|--|----|-------|--|---|

SUBTOTAL – COMMON

| | | | | | |
|-----------------------------|--|--|--|--|-----------|
| SHAREHOLDER'S EQUITY | | | | | 1,307,335 |
|-----------------------------|--|--|--|--|-----------|

COMPREHENSIVE INCOME

Other Comprehensive Income (Loss), Net
of

Taxes:

Cash Flow Hedges, Net of Tax of \$232 (431) (431)

Amortization of Pension and OPEB

Deferred

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| | | | | | | |
|----------------------------|----------|-----------|-----------|------------|---|-------------|
| Costs, Net of Tax of \$667 | | | | 1,238 | | 1,238 |
| NET INCOME | | | 103,766 | | | 103,766 |
| TOTAL COMPREHENSIVE INCOME | | | | | | 104,573 |
| | | | | | | |
| TOTAL COMMON SHAREHOLDER'S | | | | | | |
| EQUITY – JUNE 30, 2010 | \$41,026 | \$580,742 | \$839,326 | \$ (49,186 |) | \$1,411,908 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS

ASSETS

June 30, 2010 and December 31, 2009

(in thousands)

(Unaudited)

| | 2010 | 2009 |
|--|--------------------|--------------------|
| CURRENT ASSETS | | |
| Cash and Cash Equivalents | \$1,193 | \$1,096 |
| Other Cash Deposits | 5,861 | 16,150 |
| Advance to Affiliates | 57,069 | - |
| Accounts Receivable: | | |
| Customers | 50,518 | 37,158 |
| Affiliated Companies | 21,444 | 28,555 |
| Accrued Unbilled Revenues | 23,152 | 11,845 |
| Miscellaneous | 2,558 | 4,164 |
| Allowance for Uncollectible Accounts | (1,973) | (3,481) |
| Total Accounts Receivable | 95,699 | 78,241 |
| Fuel | 77,268 | 74,158 |
| Materials and Supplies | 40,054 | 39,652 |
| Emission Allowances | 23,190 | 26,587 |
| Risk Management Assets | 30,962 | 34,343 |
| Accrued Tax Benefits | 47,966 | 29,273 |
| Margin Deposits | 13,281 | 14,874 |
| Prepayments and Other Current Assets | 13,851 | 6,349 |
| TOTAL CURRENT ASSETS | 406,394 | 320,723 |
| PROPERTY, PLANT AND EQUIPMENT | | |
| Electric: | | |
| Production | 2,648,583 | 2,641,860 |
| Transmission | 639,205 | 623,680 |
| Distribution | 1,762,600 | 1,745,559 |
| Other Property, Plant and Equipment | 202,368 | 189,315 |
| Construction Work in Progress | 157,297 | 155,081 |
| Total Property, Plant and Equipment | 5,410,053 | 5,355,495 |
| Accumulated Depreciation and Amortization | 1,892,328 | 1,838,840 |
| TOTAL PROPERTY, PLANT AND EQUIPMENT – NET | 3,517,725 | 3,516,655 |
| OTHER NONCURRENT ASSETS | | |
| Regulatory Assets | 317,426 | 341,029 |
| Long-term Risk Management Assets | 27,204 | 23,882 |
| Deferred Charges and Other Noncurrent Assets | 98,544 | 147,217 |
| TOTAL OTHER NONCURRENT ASSETS | 443,174 | 512,128 |
| TOTAL ASSETS | \$4,367,293 | \$4,349,506 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
June 30, 2010 and December 31, 2009
(Unaudited)

| | 2010 | 2009 |
|--|----------------|-------------|
| | (in thousands) | |
| CURRENT LIABILITIES | | |
| Advances from Affiliates | \$- | \$24,202 |
| Accounts Payable: | | |
| General | 83,021 | 95,872 |
| Affiliated Companies | 64,933 | 81,338 |
| Long-term Debt Due Within One Year – Nonaffiliated | 150,000 | 150,000 |
| Long-term Debt Due Within One Year – Affiliated | - | 100,000 |
| Risk Management Liabilities | 14,021 | 13,052 |
| Customer Deposits | 28,964 | 27,911 |
| Accrued Taxes | 127,589 | 199,001 |
| Accrued Interest | 23,046 | 24,669 |
| Other Current Liabilities | 89,625 | 67,053 |
| TOTAL CURRENT LIABILITIES | 581,199 | 783,098 |
| NONCURRENT LIABILITIES | | |
| Long-term Debt – Nonaffiliated | 1,438,673 | 1,286,393 |
| Long-term Risk Management Liabilities | 11,165 | 10,313 |
| Deferred Income Taxes | 549,059 | 535,265 |
| Regulatory Liabilities and Deferred Investment Tax Credits | 174,600 | 174,671 |
| Employee Benefits and Pension Obligations | 129,368 | 133,968 |
| Deferred Credits and Other Noncurrent Liabilities | 71,321 | 65,963 |
| TOTAL NONCURRENT LIABILITIES | 2,374,186 | 2,206,573 |
| TOTAL LIABILITIES | 2,955,385 | 2,989,671 |
| Rate Matters (Note 3) | | |
| Commitments and Contingencies (Note 4) | | |
| COMMON SHAREHOLDER’S EQUITY | | |
| Common Stock – No Par Value: | | |
| Authorized – 24,000,000 Shares | | |
| Outstanding – 16,410,426 Shares | 41,026 | 41,026 |
| Paid-in Capital | 580,742 | 580,663 |
| Retained Earnings | 839,326 | 788,139 |
| Accumulated Other Comprehensive Income (Loss) | (49,186) | (49,993) |
| TOTAL COMMON SHAREHOLDER’S EQUITY | 1,411,908 | 1,359,835 |
| TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY | \$4,367,293 | \$4,349,506 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Six Months Ended June 30, 2010 and 2009

(in thousands)

(Unaudited)

| | 2010 | 2009 |
|--|------------|------------|
| OPERATING ACTIVITIES | | |
| Net Income | \$ 103,766 | \$ 133,036 |
| Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities: | | |
| Depreciation and Amortization | 75,089 | 69,571 |
| Deferred Income Taxes | 19,833 | 60,104 |
| Carrying Costs Income | (4,184) | (3,410) |
| Allowance for Equity Funds Used During Construction | (1,235) | (1,885) |
| Mark-to-Market of Risk Management Contracts | 1,466 | (10,671) |
| Property Taxes | 48,526 | 44,075 |
| Fuel Over/Under-Recovery, Net | 32,120 | (33,963) |
| Change in Other Noncurrent Assets | (12,867) | (10,738) |
| Change in Other Noncurrent Liabilities | (2,458) | 20,003 |
| Changes in Certain Components of Working Capital: | | |
| Accounts Receivable, Net | (17,458) | 46,738 |
| Fuel, Materials and Supplies | (3,512) | (29,021) |
| Accounts Payable | (12,744) | (84,284) |
| Customer Deposits | 1,053 | 1,390 |
| Accrued Taxes, Net | (89,647) | (60,756) |
| Other Current Assets | 8,582 | 3,600 |
| Other Current Liabilities | 11,209 | 5,772 |
| Net Cash Flows from Operating Activities | 157,539 | 149,561 |
| INVESTING ACTIVITIES | | |
| Construction Expenditures | (84,208) | (147,128) |
| Change in Other Cash Deposits | 10,289 | 11,075 |
| Change in Advances to Affiliates, Net | (57,069) | - |
| Acquisitions of Assets | (463) | (184) |
| Proceeds from Sales of Assets | 3,410 | 465 |
| Net Cash Flows Used for Investing Activities | (128,041) | (135,772) |
| FINANCING ACTIVITIES | | |
| Issuance of Long-term Debt - Nonaffiliated | 149,443 | - |
| Change in Advances from Affiliates, Net | (24,202) | 87,794 |
| Retirement of Long-term Debt - Affiliated | (100,000) | - |
| Principal Payments for Capital Lease Obligations | (2,237) | (1,333) |
| Dividends Paid on Common Stock | (52,500) | (100,000) |
| Other Financing Activities | 95 | - |
| Net Cash Flows Used for Financing Activities | (29,401) | (13,539) |
| Net Increase in Cash and Cash Equivalents | 97 | 250 |
| Cash and Cash Equivalents at Beginning of Period | 1,096 | 1,063 |
| Cash and Cash Equivalents at End of Period | \$ 1,193 | \$ 1,313 |

SUPPLEMENTARY INFORMATION

| | | | | |
|--|----|--------|----|--------|
| Cash Paid for Interest, Net of Capitalized Amounts | \$ | 43,615 | \$ | 53,045 |
| Net Cash Paid for Income Taxes | | 54,032 | | 1,239 |
| Noncash Acquisitions Under Capital Leases | | 9,196 | | 565 |
| Construction Expenditures Included in Accounts Payable at June 30, | | 14,594 | | 42,894 |
| Noncash Dividend of Property to Parent | | - | | 8,123 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

COLUMBUS SOUTHERN POWER COMPANY AND SUBSIDIARIES
INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF
REGISTRANT SUBSIDIARIES

The condensed notes to CSPCo's condensed consolidated financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to CSPCo. The footnotes begin on page 156.

| | Footnote Reference |
|---|-----------------------|
| Significant Accounting Matters | Note 1 |
| New Accounting Pronouncements | Note 2 |
| Rate Matters | Note 3 |
| Commitments, Guarantees and Contingencies | Note 4 |
| Benefit Plans | Note 6 |
| Business Segments | Note 7 |
| Derivatives and Hedging | Note 8 |
| Fair Value Measurements | Note 9 |
| Income Taxes | Note 10 |
| Financing Activities | Note 11 |
| Cost Reduction Initiatives | Note 12 |

INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

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INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE FINANCIAL DISCUSSION AND ANALYSIS

RESULTS OF OPERATIONS

Second Quarter of 2010 Compared to Second Quarter of 2009

Reconciliation of Second Quarter of 2009 to Second Quarter of 2010

Net Income

(in millions)

| | | |
|----------------------------------|----|-------|
| Second Quarter of 2009 | \$ | 49 |
| Changes in Gross Margin: | | |
| Retail Margins | | 47 |
| FERC Municipals and Cooperatives | | (8) |
| Other Revenues | | (42) |
| Total Change in Gross Margin | | (3) |
| Total Expenses and Other: | | |
| Other Operation and Maintenance | | (46) |
| Taxes Other Than Income Taxes | | (1) |
| Other Income | | 2 |
| Total Expenses and Other | | (45) |
| Income Tax Expense | | 14 |
| Second Quarter of 2010 | \$ | 15 |

The major components of the decrease in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins increased \$47 million primarily due to the following:
 - A \$20 million increase in fuel margins primarily due to higher fuel and purchased power costs recorded in 2009 related to the Cook Plant Unit 1 (Unit 1) shutdown. This increase in fuel margins was offset by a corresponding decrease in Other Revenues as discussed below.
 - A \$15 million increase in usage for residential and commercial customers primarily due to an increase in cooling degree days and demand.
 - An \$11 million increase in industrial sales margins due to higher usage reflecting an improvement in demand.
- FERC Municipals and Cooperatives margins decreased \$8 million primarily due to a unit power sales agreement ending in December 2009.
- Other Revenues decreased \$42 million primarily due to the Cook Plant accidental outage insurance proceeds of \$46 million which ended when Unit 1 returned to service in December 2009. I&M reduced customer bills by approximately \$20 million in the second quarter of 2009 for the cost of replacement power resulting from the Unit 1 outage. This decrease in insurance proceeds was offset by a corresponding increase in Retail Margins as discussed above.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses increased \$46 million primarily due to the following:
 - A \$40 million increase in expenses related to the cost reduction initiatives in the second quarter of 2010.
 - A \$4 million increase in distribution expenses associated with storm restoration expenses from June 2010 storms.
 - A \$3 million increase in transmission expense due to lower credits under the Transmission Agreement.
- Income Tax Expense decreased \$14 million primarily due to a decrease in pretax book income.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009

Reconciliation of Six Months Ended June 30, 2009 to Six Months Ended June 30, 2010

Net Income

(in millions)

| | | |
|----------------------------------|----|------|
| Six Months Ended June 30, 2009 | \$ | 129 |
| Changes in Gross Margin: | | |
| Retail Margins | | 82 |
| FERC Municipals And Cooperatives | | (16) |
| Off-system Sales | | 3 |
| Transmission Revenues | | 1 |
| Other Revenues | | (97) |
| Total Change in Gross Margin | | (27) |
| Total Expenses and Other: | | |
| Other Operation and Maintenance | | (69) |
| Depreciation and Amortization | | (1) |
| Taxes Other Than Income Taxes | | (1) |
| Other Income | | 3 |
| Interest Expense | | (3) |
| Total Expenses and Other | | (71) |
| Income Tax Expense | | 29 |
| Six Months Ended June 30, 2010 | \$ | 60 |

The major components of the decrease in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins increased \$82 million primarily due to the following:
 - A \$42 million increase in fuel margins due to higher fuel and purchased power costs recorded in 2009 related to the Unit 1 shutdown. This increase in fuel margins was offset by a corresponding decrease in Other Revenues as discussed below.
 - A \$19 million increase in industrial sale margins due to higher usage reflecting an improvement in demand.
 - A \$17 million increase in usage and price for residential and commercial customers primarily due to an increase in cooling degree days and demand.
 - A \$5 million increase in capacity settlements under the Interconnection Agreement.
- FERC Municipals and Cooperatives margins decreased \$16 million primarily due to a unit power sales agreement ending in December 2009.
- Other Revenues decreased \$97 million primarily due to the Cook Plant accidental outage insurance proceeds of \$99 million which ended when Unit 1 returned to service in December 2009. I&M reduced customer bills by approximately \$42 million in the first six months of 2009 for the cost of replacement power resulting from the Unit 1 outage. This decrease in insurance proceeds was offset by a corresponding increase in Retail Margins as discussed above.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses increased \$69 million primarily due to the following:
 - A \$40 million increase due to expenses related to the cost reduction initiatives in the second quarter of 2010.
 - A \$10 million increase in administrative and general expenses primarily due to a \$7 million increase in benefit and insurance costs and a \$2 million increase in property insurance.
 - A \$6 million increase in transmission expense primarily due to lower credits under the Transmission Agreement.
 - A \$4 million increase in distribution expenses associated with storm restoration expenses from June 2010 storms.
- Income Tax Expense decreased \$29 million primarily due to a decrease in pretax book income.

REGULATORY ACTIVITY

Michigan Regulatory Activity

In January 2010, I&M filed with the MPSC a request for a \$63 million increase in annual base rates based on an 11.75% return on common equity. In the August 2010 billing cycle, I&M, with the MPSC authorization, will implement a \$44 million interim rate increase, subject to refund with interest. In July 2010, the MPSC staff filed testimony which recommended a \$34 million annual increase in base rates based on a 10.35% return on common equity plus separate recovery of approximately \$7 million of customer choice implementation costs over a two year period. The MPSC must issue a final order within one year of the original filing. See “Michigan Base Rate Filing” section of Note 3.

SIGNIFICANT FACTORS

REGULATORY ISSUES

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in a fire on the electric generator. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately \$395 million. Management believes that I&M should recover a significant portion of repair and replacement costs through the turbine vendor’s warranty, insurance and the regulatory process. I&M repaired Unit 1 and it resumed operations in December 2009 at slightly reduced power. The Unit 1 rotors were repaired and reinstalled due to the extensive lead time required to manufacture and install new turbine rotors. As a result, the replacement of the repaired turbine rotors and other equipment is scheduled for the Unit 1 planned outage in the fall of 2011. If the ultimate costs of the incident are not covered by warranty, insurance or through the related regulatory process or if any future regulatory proceedings are adverse, it could have an adverse impact on net income, cash flows and financial condition. See “Cook Plant Unit 1 Fire and Shutdown” section of Note 4.

LITIGATION AND ENVIRONMENTAL ISSUES

In the ordinary course of business, I&M is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual resolution will be or the timing and amount of any loss, fine or penalty may be. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be

estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2009 Annual Report. Also, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 156. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

See the “Significant Factors” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” section beginning on page 224 for additional discussion of relevant factors.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the “Critical Accounting Policies and Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” in the 2009 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets and pension and other postretirement benefits.

See the “New Accounting Pronouncements” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” beginning on page 224 for a discussion of the adoption and impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

See “Quantitative And Qualitative Disclosures About Risk Management Activities” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” beginning on page 224 for a discussion of risk management activities.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

For the Three and Six Months Ended June 30, 2010 and 2009

(in thousands)

(Unaudited)

| | Three Months Ended | | Six Months Ended | |
|---|--------------------|-----------------|------------------|------------------|
| | 2010 | 2009 | 2010 | 2009 |
| REVENUES | | | | |
| Electric Generation, Transmission and Distribution | \$408,702 | \$400,347 | \$846,726 | \$822,274 |
| Sales to AEP Affiliates | 67,473 | 57,385 | 151,690 | 117,371 |
| Other Revenues - Affiliated | 30,685 | 25,192 | 58,651 | 55,932 |
| Other Revenues - Nonaffiliated | 3,055 | 47,492 | 5,904 | 101,883 |
| TOTAL REVENUES | 509,915 | 530,416 | 1,062,971 | 1,097,460 |
| EXPENSES | | | | |
| Fuel and Other Consumables Used for Electric Generation | 102,258 | 108,202 | 221,439 | 211,162 |
| Purchased Electricity for Resale | 31,444 | 30,853 | 61,211 | 69,214 |
| Purchased Electricity from AEP Affiliates | 68,496 | 80,893 | 150,746 | 160,871 |
| Other Operation | 162,978 | 115,224 | 293,659 | 224,684 |
| Maintenance | 49,633 | 51,488 | 98,077 | 97,762 |
| Depreciation and Amortization | 33,971 | 33,629 | 67,802 | 66,374 |
| Taxes Other Than Income Taxes | 18,995 | 18,253 | 40,027 | 38,949 |
| TOTAL EXPENSES | 467,775 | 438,542 | 932,961 | 869,016 |
| OPERATING INCOME | 42,140 | 91,874 | 130,010 | 228,444 |
| Other Income (Expense): | | | | |
| Interest Income | 1,034 | 974 | 1,519 | 3,517 |
| Allowance for Equity Funds Used During Construction | 4,567 | 2,783 | 9,002 | 4,338 |
| Interest Expense | (26,410) | (26,173) | (52,511) | (49,704) |
| INCOME BEFORE INCOME TAX EXPENSE | 21,331 | 69,458 | 88,020 | 186,595 |
| Income Tax Expense | 6,729 | 20,949 | 28,360 | 57,134 |
| NET INCOME | 14,602 | 48,509 | 59,660 | 129,461 |
| Preferred Stock Dividend Requirements | 85 | 85 | 170 | 170 |
| EARNINGS ATTRIBUTABLE TO COMMON STOCK | \$14,517 | \$48,424 | \$59,490 | \$129,291 |

The common stock of I&M is wholly-owned by AEP.

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME (LOSS)

For the Six Months Ended June 30, 2010 and 2009

(in thousands)

(Unaudited)

| | Common Stock | Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
|--|-----------------|--------------------|----------------------|--|-------------|
| TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2008 | \$56,584 | \$861,291 | \$538,637 | \$ (21,694) | \$1,434,818 |
| Capital Contribution from Parent | | 120,000 | | | 120,000 |
| Common Stock Dividends | | | (49,000) | | (49,000) |
| Preferred Stock Dividends | | | (170) | | (170) |
| Gain on Reacquired Preferred Stock | | 1 | | | 1 |
| SUBTOTAL – COMMON SHAREHOLDER'S EQUITY | | | | | 1,505,649 |
| COMPREHENSIVE INCOME | | | | | |
| Other Comprehensive Income, Net of Taxes: | | | | | |
| Cash Flow Hedges, Net of Tax of \$103 | | | | 192 | 192 |
| Amortization of Pension and OPEB Deferred | | | | | |
| Costs, Net of Tax of \$184 | | | | 341 | 341 |
| NET INCOME | | | 129,461 | | 129,461 |
| TOTAL COMPREHENSIVE INCOME | | | | | 129,994 |
| TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2009 | \$56,584 | \$981,292 | \$618,928 | \$ (21,161) | \$1,635,643 |
| TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2009 | \$56,584 | \$981,292 | \$656,608 | \$ (21,701) | \$1,672,783 |
| Common Stock Dividends | | | (51,500) | | (51,500) |
| Preferred Stock Dividends | | | (170) | | (170) |
| SUBTOTAL – COMMON SHAREHOLDER'S EQUITY | | | | | 1,621,113 |
| COMPREHENSIVE INCOME | | | | | |
| Other Comprehensive Income, Net of Taxes: | | | | | |
| Cash Flow Hedges, Net of Tax of \$39 | | | | 72 | 72 |
| Amortization of Pension and OPEB Deferred | | | | | |
| Costs, Net of Tax of \$235 | | | | 436 | 436 |

| | | | | | | |
|----------------------------|----------|-----------|-----------|------------|---|-------------|
| NET INCOME | | | 59,660 | | | 59,660 |
| TOTAL COMPREHENSIVE INCOME | | | | | | 60,168 |
| TOTAL COMMON SHAREHOLDER'S | | | | | | |
| EQUITY – JUNE 30, 2010 | \$56,584 | \$981,292 | \$664,598 | \$ (21,193 |) | \$1,681,281 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS

ASSETS

June 30, 2010 and December 31, 2009

(in thousands)

(Unaudited)

| | 2010 | 2009 |
|--|--------------------|--------------------|
| CURRENT ASSETS | | |
| Cash and Cash Equivalents | \$732 | \$779 |
| Advances to Affiliates | 126,515 | 114,012 |
| Accounts Receivable: | | |
| Customers | 86,002 | 71,120 |
| Affiliated Companies | 68,632 | 83,248 |
| Accrued Unbilled Revenues | 4,243 | 8,762 |
| Miscellaneous | 15,702 | 8,638 |
| Allowance for Uncollectible Accounts | (2,111) | (2,265) |
| Total Accounts Receivable | 172,468 | 169,503 |
| Fuel | 107,293 | 79,554 |
| Materials and Supplies | 163,532 | 164,439 |
| Risk Management Assets | 32,803 | 34,438 |
| Accrued Tax Benefits | 147,959 | 144,473 |
| Deferred Cook Plant Fire Costs | 53,218 | 134,322 |
| Prepayments and Other Current Assets | 25,833 | 29,395 |
| TOTAL CURRENT ASSETS | 830,353 | 870,915 |
| PROPERTY, PLANT AND EQUIPMENT | | |
| Electric: | | |
| Production | 3,652,725 | 3,634,215 |
| Transmission | 1,168,195 | 1,154,026 |
| Distribution | 1,382,429 | 1,360,553 |
| Other Property, Plant and Equipment (including nuclear fuel and coal mining) | 748,725 | 755,132 |
| Construction Work in Progress | 329,245 | 278,278 |
| Total Property, Plant and Equipment | 7,281,319 | 7,182,204 |
| Accumulated Depreciation, Depletion and Amortization | 3,105,441 | 3,073,695 |
| TOTAL PROPERTY, PLANT AND EQUIPMENT – NET | 4,175,878 | 4,108,509 |
| OTHER NONCURRENT ASSETS | | |
| Regulatory Assets | 517,700 | 496,464 |
| Spent Nuclear Fuel and Decommissioning Trusts | 1,391,428 | 1,391,919 |
| Long-term Risk Management Assets | 36,177 | 29,134 |
| Deferred Charges and Other Noncurrent Assets | 76,365 | 82,047 |
| TOTAL OTHER NONCURRENT ASSETS | 2,021,670 | 1,999,564 |
| TOTAL ASSETS | \$7,027,901 | \$6,978,988 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
June 30, 2010 and December 31, 2009
(Unaudited)

| | 2010 | 2009 |
|---|----------------|-------------|
| | (in thousands) | |
| CURRENT LIABILITIES | | |
| Accounts Payable: | | |
| General | \$91,297 | \$171,192 |
| Affiliated Companies | 55,208 | 61,315 |
| Long-term Debt Due Within One Year – Nonaffiliated DCC Fuel Bonds | 61,435 | 37,544 |
| Long-term Debt Due Within One Year – Affiliated | - | 25,000 |
| Risk Management Liabilities | 14,108 | 13,436 |
| Customer Deposits | 28,748 | 27,711 |
| Accrued Taxes | 63,131 | 56,814 |
| Accrued Interest | 27,588 | 27,633 |
| Obligations Under Capital Leases | 20,981 | 25,065 |
| Other Current Liabilities | 156,678 | 126,800 |
| TOTAL CURRENT LIABILITIES | 519,174 | 572,510 |
| NONCURRENT LIABILITIES | | |
| Long-term Debt – Nonaffiliated | 2,057,239 | 2,015,362 |
| Long-term Risk Management Liabilities | 11,249 | 10,386 |
| Deferred Income Taxes | 728,741 | 696,163 |
| Regulatory Liabilities and Deferred Investment Tax Credits | 753,515 | 756,845 |
| Asset Retirement Obligations | 923,666 | 894,746 |
| Deferred Credits and Other Noncurrent Liabilities | 344,959 | 352,116 |
| TOTAL NONCURRENT LIABILITIES | 4,819,369 | 4,725,618 |
| TOTAL LIABILITIES | 5,338,543 | 5,298,128 |
| Cumulative Preferred Stock Not Subject to Mandatory Redemption | 8,077 | 8,077 |
| Rate Matters (Note 3) | | |
| Commitments and Contingencies (Note 4) | | |
| COMMON SHAREHOLDER’S EQUITY | | |
| Common Stock – No Par Value: | | |
| Authorized – 2,500,000 Shares | | |
| Outstanding – 1,400,000 Shares | 56,584 | 56,584 |
| Paid-in Capital | 981,292 | 981,292 |
| Retained Earnings | 664,598 | 656,608 |
| Accumulated Other Comprehensive Income (Loss) | (21,193) | (21,701) |
| TOTAL COMMON SHAREHOLDER’S EQUITY | 1,681,281 | 1,672,783 |
| TOTAL LIABILITIES AND SHAREHOLDERS’ EQUITY | \$7,027,901 | \$6,978,988 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Six Months Ended June 30, 2010 and 2009

(in thousands)

(Unaudited)

| | 2010 | 2009 |
|--|-----------|------------|
| OPERATING ACTIVITIES | | |
| Net Income | \$ 59,660 | \$ 129,461 |
| Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities: | | |
| Depreciation and Amortization | 67,802 | 66,374 |
| Deferred Income Taxes | 23,213 | 92,892 |
| Deferral of Incremental Nuclear Refueling Outage Expenses, Net | (16,103) | (13,928) |
| Allowance for Equity Funds Used During Construction | (9,002) | (4,338) |
| Mark-to-Market of Risk Management Contracts | (4,314) | (10,602) |
| Amortization of Nuclear Fuel | 69,478 | 24,718 |
| Fuel Over/Under Recovery, Net | 11,389 | 2,410 |
| Change in Other Noncurrent Assets | 7,224 | (8,727) |
| Change in Other Noncurrent Liabilities | 33,814 | 26,606 |
| Changes in Certain Components of Working Capital: | | |
| Accounts Receivable, Net | (2,965) | 9,383 |
| Fuel, Materials and Supplies | (26,832) | (8,668) |
| Accounts Payable | (31,079) | (62,884) |
| Accrued Taxes, Net | 4,470 | (21,736) |
| Received (Deferred) Cook Plant Fire Costs | 61,906 | (24,209) |
| Other Current Assets | (284) | (13,840) |
| Other Current Liabilities | 20,087 | (26,990) |
| Net Cash Flows from Operating Activities | 268,464 | 155,922 |
| INVESTING ACTIVITIES | | |
| Construction Expenditures | (160,797) | (162,153) |
| Change in Advances to Affiliates, Net | (12,503) | - |
| Purchases of Investment Securities | (617,059) | (441,928) |
| Sales of Investment Securities | 592,263 | 411,027 |
| Acquisitions of Nuclear Fuel | (41,357) | (152,150) |
| Other Investing Activities | (345) | 15,473 |
| Net Cash Flows Used for Investing Activities | (239,798) | (329,731) |
| FINANCING ACTIVITIES | | |
| Capital Contribution from Parent | - | 120,000 |
| Issuance of Long-term Debt - Nonaffiliated | 84,564 | 567,797 |
| Issuance of Long-term Debt - Affiliated | - | 25,000 |
| Change in Advances from Affiliates, Net | - | (473,686) |
| Retirement of Long-term Debt - Nonaffiliated | (19,208) | - |
| Retirement of Long-term Debt - Affiliated | (25,000) | - |
| Retirement of Cumulative Preferred Stock | - | (2) |

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| | | |
|--|----------|----------|
| Principal Payments for Capital Lease Obligations | (17,669) | (16,235) |
| Dividends Paid on Common Stock | (51,500) | (49,000) |
| Dividends Paid on Cumulative Preferred Stock | (170) | (170) |
| Other Financing Activities | 270 | 189 |
| Net Cash Flows from (Used for) Financing Activities | (28,713) | 173,893 |
| Net Increase (Decrease) in Cash and Cash Equivalents | (47) | 84 |
| Cash and Cash Equivalents at Beginning of Period | 779 | 728 |
| Cash and Cash Equivalents at End of Period | \$ 732 | \$ 812 |

SUPPLEMENTARY INFORMATION

| | | |
|--|-----------|-----------|
| Cash Paid for Interest, Net of Capitalized Amounts | \$ 50,759 | \$ 51,199 |
| Net Cash Paid (Received) for Income Taxes | 8,092 | (23) |
| Noncash Acquisitions Under Capital Leases | 8,844 | 1,380 |
| Construction Expenditures Included in Accounts Payable at June 30, | 19,220 | 26,763 |
| Acquisition of Nuclear Fuel Included in Accounts Payable at June 30, | 123 | 9 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF
REGISTRANT SUBSIDIARIES

The condensed notes to I&M's condensed consolidated financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to I&M. The footnotes begin on page 156.

| | Footnote Reference |
|--|-----------------------|
| Significant Accounting Matters | Note 1 |
| New Accounting Pronouncements and Extraordinary Item | Note 2 |
| Rate Matters | Note 3 |
| Commitments, Guarantees and Contingencies | Note 4 |
| Benefit Plans | Note 6 |
| Business Segments | Note 7 |
| Derivatives and Hedging | Note 8 |
| Fair Value Measurements | Note 9 |
| Income Taxes | Note 10 |
| Financing Activities | Note 11 |
| Cost Reduction Initiatives | Note 12 |

OHIO POWER COMPANY CONSOLIDATED

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OHIO POWER COMPANY CONSOLIDATED
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

RESULTS OF OPERATIONS

Second Quarter of 2010 Compared to Second Quarter of 2009

Reconciliation of Second Quarter of 2009 to Second Quarter of 2010

Net Income

(in millions)

| | | |
|---------------------------------|----|-------|
| Second Quarter of 2009 | \$ | 64 |
| Changes in Gross Margin: | | |
| Retail Margins | | 26 |
| Off-system Sales | | (7) |
| Other Revenues | | (2) |
| Total Change in Gross Margin | | 17 |
| Total Expenses and Other: | | |
| Other Operation and Maintenance | | (55) |
| Taxes Other Than Income Taxes | | (6) |
| Carrying Costs Income | | 3 |
| Other Income | | 1 |
| Interest Expense | | (4) |
| Total Expenses and Other | | (61) |
| Income Tax Expense | | 18 |
| Second Quarter of 2010 | \$ | 38 |

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins increased \$26 million primarily due to the following:
 - A \$13 million increase in retail sales as a result of an increase in weather-related usage of residential and commercial customers and an increase in usage of industrial customers resulting from an improvement in demand.
 - A \$13 million increase in capacity settlements under the Interconnection Agreement.
 - An \$8 million increase in fuel margins.
 - A \$6 million increase associated with increased demand charges from WPCo effective January 2010.

These increases were partially offset by:

- An \$8 million decrease as a result of the timing of the approval and implementation of rates set by the Ohio ESP from April through December 2009.

A \$3 million decrease related to increased consumable and allowance expenses.

- Margins from Off-system Sales decreased \$7 million primarily due to lower trading and marketing margins, partially offset by higher physical sales volumes.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses increased \$55 million primarily due to a \$49 million increase in expenses related to the cost reduction initiatives in the second quarter of 2010.
 - Taxes Other Than Income Taxes increased \$6 million primarily due to a \$2 million increase in real and property tax and a \$2 million increase due to the employer portion of payroll taxes incurred related to the cost reduction initiatives in the second quarter of 2010.
 - Carrying Costs Income increased \$3 million primarily due to higher Ohio ESP FAC carrying charges in 2010 related to an increase in the deferred fuel regulatory asset balance.
 - Interest Expense increased \$4 million primarily due to:
 - A \$7 million increase due to a prior year gain on an interest rate hedge of a forecasted debt issuance.
 - A \$5 million increase primarily due to an issuance of long-term debt in September 2009 partly offset by a retirement of long-term debt in April 2010.
- These increases were partially offset by:
- An \$8 million decrease related to the reacquisition of JMG Funding LP's (JMG) bonds during the third quarter of 2009.
 - Income Tax Expense decreased \$18 million primarily due to a decrease in pretax book income.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009

Reconciliation of Six Months Ended June 30, 2009 to Six Months Ended June 30, 2010

Net Income
(in millions)

| | | |
|---------------------------------|----|------|
| Six Months Ended June 30, 2009 | \$ | 137 |
| Changes in Gross Margin: | | |
| Retail Margins | | 68 |
| Off-system Sales | | (1) |
| Transmission Revenues | | (2) |
| Other Revenues | | (19) |
| Total Change in Gross Margin | | 46 |
| Total Expenses and Other: | | |
| Other Operation and Maintenance | | (41) |
| Depreciation and Amortization | | (6) |
| Taxes Other Than Income Taxes | | (7) |
| Carrying Costs Income | | 6 |
| Other Income | | 1 |
| Interest Expense | | (5) |
| Total Expenses and Other | | (52) |
| Income Tax Expense | | (2) |
| Six Months Ended June 30, 2010 | \$ | 129 |

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins increased \$68 million primarily due to the following:
 - A \$37 million increase in capacity settlements under the Interconnection Agreement.
 - A \$26 million increase in rate relief due to a \$14 million increase related to the implementation of higher rates set by the Ohio ESP and \$12 million of increased demand charges from WPCo effective January 2010.
 - A \$20 million increase in fuel margins.
- These increases were partially offset by:
 - A \$10 million net decrease as a result of revenue collected from the Economic Development Rider more than offset by a reduction in revenue from the 2010 Special Arrangement Discount for Ormet.
 - A \$6 million decrease related to increased consumable and allowance expenses.
- Other Revenues decreased \$19 million primarily due to reduced gains on sales of emission allowances.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses increased \$41 million primarily due to:
 - A \$49 million increase due to expenses related to the cost reduction initiatives in the second quarter of 2010.
 - A \$5 million increase in recoverable customer account expenses due to increased Universal Service Fund surcharge rates for customers who qualify for payment assistance.

These increases were partially offset by:

 - A \$7 million decrease related to a 2009 obligation to contribute to the “Partnership with Ohio” fund for low income, at-risk customers ordered by the PUCO’s March 2009 approval of OPCo’s ESP.
 - A \$7 million decrease in rent expense as a result of the purchase of JMG in July 2009.
- Depreciation and Amortization increased \$6 million primarily due to:
 - A \$9 million increase from higher depreciable property balances as a result of environmental improvements placed in service and various other property additions.

This increase was partially offset by:

 - A \$3 million decrease due to the completion of the amortization of software and leasehold improvements in the fourth quarter of 2009.
- Taxes Other Than Income Taxes increased \$7 million primarily due to a \$4 million increase in real and property tax and a \$2 million increase due to the employer portion of payroll taxes incurred related to the cost reduction initiatives in the second quarter of 2010.
- Carrying Costs Income increased \$6 million primarily due to higher Ohio ESP FAC carrying charges in 2010 related to an increase in the deferred fuel regulatory asset balance.
- Interest Expense increased \$5 million primarily due to:
 - An \$11 million increase primarily due to an issuance of long-term debt in September 2009 partly offset by a retirement of long-term debt in April 2010.
 - A \$7 million increase due to a prior year gain on an interest rate hedge of a forecasted debt issuance.
 - A \$6 million decrease in the debt component of AFUDC primarily due to the Amos Plant Unit 3 FGD and precipitator upgrade going into service in March 2009.

These increases were partially offset by:

 - A \$16 million decrease related to the reacquisition of JMG’s bonds during the third quarter of 2009.
- Income Tax Expense increased \$2 million primarily due to the tax treatment associated with the future reimbursement of Medicare Part D retiree prescription drug benefits offset in part by a decrease in pretax book income.

FINANCIAL CONDITION

LIQUIDITY

OPCo participates in the Utility Money Pool, which provides access to AEP’s liquidity. OPCo has \$200 million of Senior Unsecured Notes that will mature in the remainder of 2010. OPCo relies upon ready access to capital markets, cash flows from operations and access to the Utility Money Pool to fund its maturities, current operations and capital expenditures. See the “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” section beginning

on page 224 for additional discussion of liquidity.

Credit Ratings

Downgrades in credit ratings by one of the rating agencies could increase OPGCo's borrowing costs.

CASH FLOW

Cash flows for the six months ended June 30, 2010 and 2009 were as follows:

| | 2010 | 2009 |
|--|----------------|-----------|
| | (in thousands) | |
| Cash and Cash Equivalents at Beginning of Period | \$ 1,984 | \$ 12,679 |
| Net Cash Flows from (Used for) Operating Activities | 352,278 | (19,453) |
| Net Cash Flows from (Used for) Investing Activities | 119,588 | (296,508) |
| Net Cash Flows from (Used for) Financing Activities | (472,912) | 320,054 |
| Net Increase (Decrease) in Cash and Cash Equivalents | (1,046) | 4,093 |
| Cash and Cash Equivalents at End of Period | \$ 938 | \$ 16,772 |

Operating Activities

Net Cash Flows from Operating Activities were \$352 million in 2010. OPCo produced Net Income of \$129 million during the period and noncash expense items of \$179 million for Depreciation and Amortization and \$73 million for Deferred Income Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The current period activity in working capital relates to a number of items. Accrued Taxes, Net had a \$71 million outflow due to temporary timing differences of payments for property taxes and an increase of federal income tax related accruals. Accounts Receivable, Net had a \$44 million inflow primarily due to decreased sales to affiliates and settlement of allowance sales to affiliated companies. Fuel, Materials and Supplies had a \$26 million inflow primarily due to price decreases. The \$76 million increase in Fuel Over/Under-Recovery, Net reflects the deferral of fuel costs as a fuel clause was reactivated in 2009 under OPCo's ESP.

Net Cash Flows Used for Operating Activities were \$19 million in 2009. OPCo produced Net Income of \$137 million during the period and noncash expense items of \$173 million for Depreciation and Amortization, \$117 million for Deferred Income Taxes and \$44 million for Property Taxes offset by a \$142 million increase in Fuel Over/Under-Recovery, Net due to an under-recovery of fuel costs in Ohio. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital primarily relates to a number of items. Fuel, Materials and Supplies had a \$166 million outflow primarily due to an increase in coal inventory. Accounts Payable had a \$101 million outflow primarily due to OPCo's provision for revenue refund of \$62 million which was paid in the first quarter of 2009 to the AEP West companies as part of the FERC's order on the SIA. Accrued Taxes, Net had a \$93 million outflow due to a decrease of federal income tax related accruals and temporary timing differences of payments for property taxes.

Investing Activities

Net Cash Flows from Investing Activities were \$120 million in 2010. Net Cash Flows Used for Investing Activities were \$297 million in 2009. OPCo had a net decrease of \$266 million and a net increase of \$40 million in loans to the Utility Money Pool during 2010 and 2009, respectively. Construction Expenditures of \$148 million and \$276 million in 2010 and 2009, respectively, primarily related to environmental upgrades, as well as projects to improve service reliability for transmission and distribution. Environmental upgrades include the installation of selective catalytic reduction equipment and FGD projects at the Amos Plant.

Financing Activities

Net Cash Flows Used for Financing Activities were \$473 million in 2010. OPCo issued Pollution Control Bonds of \$86 million in March 2010 and \$79 million in May 2010. OPCo retired \$400 million of Senior Unsecured Notes in April 2010 and \$79 million of Pollution Control Bonds in June 2010. In addition, OPCo paid \$151 million of dividends on common stock.

Net Cash Flows from Financing Activities were \$320 million in 2009 primarily due to a \$550 million Capital Contribution from Parent partially offset by a net decrease of \$134 million in borrowings from the Utility Money Pool and a \$78 million retirement of Notes Payable.

Long-term debt issuances and retirements during the first six months of 2010 were:

Issuances

| Type of Debt | Principal Amount (in thousands) | Interest Rate (%) | Due Date |
|-------------------------|------------------------------------|----------------------|----------|
| Pollution Control Bonds | \$ 86,000 | 3.125 | 2015 |
| Pollution Control Bonds | 79,450 | 3.25 | 2014 |

Retirements

| Type of Debt | Principal Amount Paid (in thousands) | Interest Rate (%) | Due Date |
|-------------------------|---|----------------------|----------|
| Senior Unsecured Notes | \$ 400,000 | Variable | 2010 |
| Pollution Control Bonds | 79,450 | 7.125 | 2010 |

SUMMARY OBLIGATION INFORMATION

A summary of contractual obligations is included in the 2009 Annual Report and has not changed significantly from year-end other than debt issuances and retirements discussed in “Cash Flow” above.

SIGNIFICANT FACTORS

REGULATORY ISSUES

Ohio Electric Security Plan Filing

During 2009, the PUCO issued an order that modified and approved OPCo’s ESP which established rates through 2011. The order also limits rate increases for OPCo to 8% in 2009, 7% in 2010 and 8% in 2011. The order provides a FAC for the three-year period of the ESP. Several notices of appeal are outstanding at the Supreme Court of Ohio relating to significant issues in the determination of the approved ESP rates. OPCo will file its significantly excessive earnings test with the PUCO by the September 2010 deadline. OPCo is unable to determine whether it will be required to return any of the ESP revenues to customers. See “Ohio Electric Security Plan Filings” section of Note 3.

LITIGATION AND ENVIRONMENTAL ISSUES

In the ordinary course of business, OPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual resolution will be or the timing and amount of any loss, fine or penalty may be. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2009 Annual Report. Also, see Note 3 – Rate Matters and Note 4 –

Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 156. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

See the “Significant Factors” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” section beginning on page 224 for additional discussion of relevant factors.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the “Critical Accounting Policies and Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” in the 2009 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets and pension and other postretirement benefits.

See the “New Accounting Pronouncements” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” beginning on page 224 for a discussion of the adoption and impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

See “Quantitative And Qualitative Disclosures About Risk Management Activities” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” beginning on page 224 for a discussion of risk management activities.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2010 and 2009
(in thousands)
(Unaudited)

| | Three Months Ended | | Six Months Ended | |
|--|--------------------|-----------------|------------------|------------------|
| | 2010 | 2009 | 2010 | 2009 |
| REVENUES | | | | |
| Electric Generation, Transmission and Distribution | \$490,422 | \$457,465 | \$1,034,122 | \$982,151 |
| Sales to AEP Affiliates | 222,561 | 210,998 | 529,329 | 437,692 |
| Other Revenues - Affiliated | 5,155 | 6,281 | 11,729 | 13,769 |
| Other Revenues - Nonaffiliated | 3,826 | 3,269 | 8,057 | 7,116 |
| TOTAL REVENUES | 721,964 | 678,013 | 1,583,237 | 1,440,728 |
| EXPENSES | | | | |
| Fuel and Other Consumables Used for Electric Generation | 220,174 | 189,475 | 551,191 | 442,949 |
| Purchased Electricity for Resale | 38,746 | 43,969 | 77,636 | 96,238 |
| Purchased Electricity from AEP Affiliates | 21,583 | 20,465 | 43,774 | 37,207 |
| Other Operation | 146,417 | 96,249 | 235,573 | 195,847 |
| Maintenance | 63,472 | 58,150 | 119,703 | 118,190 |
| Depreciation and Amortization | 89,861 | 89,384 | 179,222 | 173,407 |
| Taxes Other Than Income Taxes | 52,088 | 46,482 | 105,172 | 97,974 |
| TOTAL EXPENSES | 632,341 | 544,174 | 1,312,271 | 1,161,812 |
| OPERATING INCOME | 89,623 | 133,839 | 270,966 | 278,916 |
| Other Income (Expense): | | | | |
| Carrying Costs Income | 5,681 | 2,425 | 10,555 | 4,009 |
| Other Income | 1,320 | 417 | 2,756 | 1,528 |
| Interest Expense | (39,077) | (35,241) | (79,052) | (73,922) |
| INCOME BEFORE INCOME TAX EXPENSE | 57,547 | 101,440 | 205,225 | 210,531 |
| Income Tax Expense | 19,999 | 37,528 | 75,774 | 74,010 |
| NET INCOME | 37,548 | 63,912 | 129,451 | 136,521 |
| Less: Net Income Attributable to Noncontrolling Interest | - | 553 | - | 1,016 |
| NET INCOME ATTRIBUTABLE TO OPCo | | | | |
| SHAREHOLDERS | 37,548 | 63,359 | 129,451 | 135,505 |
| Less: Preferred Stock Dividend Requirements | 183 | 183 | 366 | 366 |
| EARNINGS ATTRIBUTABLE TO OPCo COMMON | | | | |
| SHAREHOLDER | \$37,365 | \$63,176 | \$129,085 | \$135,139 |

The common stock of OPCo is wholly-owned by AEP.

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
EQUITY AND COMPREHENSIVE INCOME (LOSS)

For the Six Months Ended June 30, 2010 and 2009

(in thousands)

(Unaudited)

| | OPCo Common Shareholder | | | | | |
|--|-------------------------|--------------|--------------|---|----------------------------|--------------|
| | Common | Paid-in | Retained | Accumulated Other Comprehensive Income (Loss) | Noncontrolling Interest | Total |
| | Stock | Capital | Earnings | | | |
| TOTAL EQUITY – DECEMBER 31, 2008 | \$ 321,201 | \$ 536,640 | \$ 1,697,962 | \$ (133,858) | \$ 16,799 | \$ 2,438,744 |
| Capital Contribution from Parent | | 550,000 | | | | 550,000 |
| Common Stock Dividends - Affiliated | | | (25,000) | | | (25,000) |
| Common Stock Dividends - Nonaffiliated | | | | | (1,016) | (1,016) |
| Preferred Stock Dividends | | | (366) | | | (366) |
| Other Changes in Equity | | | | | 1,111 | 1,111 |
| SUBTOTAL – EQUITY | | | | | | 2,963,473 |
| COMPREHENSIVE INCOME | | | | | | |
| Other Comprehensive Income, Net of Taxes: | | | | | | |
| Cash Flow Hedges, Net of Tax of \$7,828 | | | | 14,538 | | 14,538 |
| Amortization of Pension and OPEB | | | | | | |
| Deferred Costs, Net of Tax of \$1,459 | | | | 2,709 | | 2,709 |
| NET INCOME | | | 135,505 | | 1,016 | 136,521 |
| TOTAL COMPREHENSIVE INCOME | | | | | | 153,768 |
| TOTAL EQUITY – JUNE 30, 2009 | \$ 321,201 | \$ 1,086,640 | \$ 1,808,101 | \$ (116,611) | \$ 17,910 | \$ 3,117,241 |
| TOTAL COMMON SHAREHOLDER'S | \$ 321,201 | \$ 1,123,149 | \$ 1,908,803 | \$ (118,458) | \$ - | \$ 3,234,695 |

**EQUITY – DECEMBER
31, 2009**

| | | |
|---|------------|------------------|
| Common Stock | | |
| Dividends | (150,575) | (150,575) |
| Preferred Stock | | |
| Dividends | (366) | (366) |
| SUBTOTAL – COMMON SHAREHOLDER'S EQUITY | | 3,083,754 |

**COMPREHENSIVE
INCOME**

| | | |
|---|----------------|----------------|
| Other Comprehensive Income (Loss), Net of Taxes: | | |
| Cash Flow Hedges, Net of Tax of \$676 | (1,255) | (1,255) |
| Amortization of Pension and OPEB Deferred Costs, Net of Tax of \$1,897 | 3,523 | 3,523 |
| NET INCOME | 129,451 | 129,451 |
| TOTAL COMPREHENSIVE INCOME | | 131,719 |

**TOTAL COMMON
SHAREHOLDER'S
EQUITY – JUNE 30,**

| | | | | | | |
|------|------------|--------------|--------------|---------------|------|--------------|
| 2010 | \$ 321,201 | \$ 1,123,149 | \$ 1,887,313 | \$ (116,190) | \$ - | \$ 3,215,473 |
|------|------------|--------------|--------------|---------------|------|--------------|

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS

ASSETS

June 30, 2010 and December 31, 2009

(in thousands)

(Unaudited)

| | 2010 | 2009 |
|--|--------------------|--------------------|
| CURRENT ASSETS | | |
| Cash and Cash Equivalents | \$938 | \$1,984 |
| Advances to Affiliates | 172,751 | 438,352 |
| Accounts Receivable: | | |
| Customers | 71,608 | 60,711 |
| Affiliated Companies | 139,427 | 200,579 |
| Accrued Unbilled Revenues | 21,630 | 15,021 |
| Miscellaneous | 2,320 | 2,701 |
| Allowance for Uncollectible Accounts | (2,665) | (2,665) |
| Total Accounts Receivable | 232,320 | 276,347 |
| Fuel | 304,977 | 336,866 |
| Materials and Supplies | 121,867 | 115,486 |
| Risk Management Assets | 40,071 | 50,048 |
| Accrued Tax Benefits | 166,875 | 143,473 |
| Prepayments and Other Current Assets | 24,769 | 26,301 |
| TOTAL CURRENT ASSETS | 1,064,568 | 1,388,857 |
| PROPERTY, PLANT AND EQUIPMENT | | |
| Electric: | | |
| Production | 6,788,912 | 6,731,469 |
| Transmission | 1,202,373 | 1,166,557 |
| Distribution | 1,595,110 | 1,567,871 |
| Other Property, Plant and Equipment | 373,811 | 348,718 |
| Construction Work in Progress | 187,230 | 198,843 |
| Total Property, Plant and Equipment | 10,147,436 | 10,013,458 |
| Accumulated Depreciation and Amortization | 3,470,968 | 3,318,896 |
| TOTAL PROPERTY, PLANT AND EQUIPMENT – NET | 6,676,468 | 6,694,562 |
| OTHER NONCURRENT ASSETS | | |
| Regulatory Assets | 845,503 | 742,905 |
| Long-term Risk Management Assets | 31,506 | 28,003 |
| Deferred Charges and Other Noncurrent Assets | 139,122 | 184,812 |
| TOTAL OTHER NONCURRENT ASSETS | 1,016,131 | 955,720 |
| TOTAL ASSETS | \$8,757,167 | \$9,039,139 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
June 30, 2010 and December 31, 2009
(Unaudited)

| | 2010 | 2009 |
|--|----------------|-------------|
| | (in thousands) | |
| CURRENT LIABILITIES | | |
| Accounts Payable: | | |
| General | \$140,269 | \$182,848 |
| Affiliated Companies | 91,992 | 92,766 |
| Long-term Debt Due Within One Year – Nonaffiliated | 200,000 | 679,450 |
| Risk Management Liabilities | 19,972 | 24,391 |
| Customer Deposits | 26,723 | 22,409 |
| Accrued Taxes | 155,946 | 203,335 |
| Accrued Interest | 45,623 | 46,431 |
| Other Current Liabilities | 149,314 | 104,889 |
| TOTAL CURRENT LIABILITIES | 829,839 | 1,356,519 |
| NONCURRENT LIABILITIES | | |
| Long-term Debt – Nonaffiliated | 2,529,248 | 2,363,055 |
| Long-term Debt – Affiliated | 200,000 | 200,000 |
| Long-term Risk Management Liabilities | 13,401 | 12,510 |
| Deferred Income Taxes | 1,379,968 | 1,302,939 |
| Regulatory Liabilities and Deferred Investment Tax Credits | 137,944 | 128,187 |
| Employee Benefits and Pension Obligations | 252,832 | 269,485 |
| Deferred Credits and Other Noncurrent Liabilities | 181,835 | 155,122 |
| TOTAL NONCURRENT LIABILITIES | 4,695,228 | 4,431,298 |
| TOTAL LIABILITIES | 5,525,067 | 5,787,817 |
| Cumulative Preferred Stock Not Subject to Mandatory Redemption | 16,627 | 16,627 |
| Rate Matters (Note 3) | | |
| Commitments and Contingencies (Note 4) | | |
| COMMON SHAREHOLDER’S EQUITY | | |
| Common Stock – No Par Value: | | |
| Authorized – 40,000,000 Shares | | |
| Outstanding – 27,952,473 Shares | 321,201 | 321,201 |
| Paid-in Capital | 1,123,149 | 1,123,149 |
| Retained Earnings | 1,887,313 | 1,908,803 |
| Accumulated Other Comprehensive Income (Loss) | (116,190) | (118,458) |
| TOTAL COMMON SHAREHOLDER’S EQUITY | 3,215,473 | 3,234,695 |
| TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY | \$8,757,167 | \$9,039,139 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

OHIO POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2010 and 2009
(in thousands)
(Unaudited)

| | 2010 | 2009 |
|---|------------|------------|
| OPERATING ACTIVITIES | | |
| Net Income | \$ 129,451 | \$ 136,521 |
| Adjustments to Reconcile Net Income to Net Cash Flows from (Used for) | | |
| Operating Activities: | | |
| Depreciation and Amortization | 179,222 | 173,407 |
| Deferred Income Taxes | 72,638 | 117,372 |
| Carrying Costs Income | (10,555) | (4,009) |
| Allowance for Equity Funds Used During Construction | (2,017) | (768) |
| Mark-to-Market of Risk Management Contracts | 2,359 | (16,123) |
| Property Taxes | 48,578 | 44,125 |
| Fuel Over/Under-Recovery, Net | (75,987) | (141,874) |
| Change in Other Noncurrent Assets | (7,571) | 6,483 |
| Change in Other Noncurrent Liabilities | (2,326) | 15,173 |
| Changes in Certain Components of Working Capital: | | |
| Accounts Receivable, Net | 44,027 | 20,986 |
| Fuel, Materials and Supplies | 25,508 | (165,648) |
| Accounts Payable | (23,991) | (100,613) |
| Accrued Taxes, Net | (71,199) | (93,152) |
| Other Current Assets | 2,680 | (14,965) |
| Other Current Liabilities | 41,461 | 3,632 |
| Net Cash Flows from (Used for) Operating Activities | 352,278 | (19,453) |
| INVESTING ACTIVITIES | | |
| Construction Expenditures | (147,831) | (276,255) |
| Change in Advances to Affiliates, Net | 265,601 | (40,319) |
| Acquisitions of Assets | (2,113) | (1,075) |
| Proceeds from Sales of Assets | 4,245 | 17,261 |
| Other Investing Activities | (314) | 3,880 |
| Net Cash Flows from (Used for) Investing Activities | 119,588 | (296,508) |
| FINANCING ACTIVITIES | | |
| Capital Contribution from Parent | - | 550,000 |
| Issuance of Long-term Debt – Nonaffiliated | 163,944 | (445) |
| Change in Short-term Debt, Net – Nonaffiliated | - | 11,500 |
| Change in Advances from Affiliates, Net | - | (133,887) |
| Retirement of Long-term Debt – Nonaffiliated | (479,450) | (77,500) |
| Retirement of Cumulative Preferred Stock | - | (1) |
| Principal Payments for Capital Lease Obligations | (3,903) | (2,224) |
| Dividends Paid on Common Stock – Nonaffiliated | - | (463) |
| Dividends Paid on Common Stock – Affiliated | (150,575) | (25,000) |
| Dividends Paid on Cumulative Preferred Stock | (366) | (366) |
| Other Financing Activities | (2,562) | (1,560) |

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| | | |
|--|-----------|-----------|
| Net Cash Flows from (Used for) Financing Activities | (472,912) | 320,054 |
| Net Increase (Decrease) in Cash and Cash Equivalents | (1,046) | 4,093 |
| Cash and Cash Equivalents at Beginning of Period | 1,984 | 12,679 |
| Cash and Cash Equivalents at End of Period | \$ 938 | \$ 16,772 |

SUPPLEMENTARY INFORMATION

| | | |
|--|-----------|------------|
| Cash Paid for Interest, Net of Capitalized Amounts | \$ 78,747 | \$ 100,522 |
| Net Cash Paid for Income Taxes | 27,206 | 2,566 |
| Noncash Acquisitions Under Capital Leases | 23,489 | 468 |
| Construction Expenditures Included in Accounts Payable at June 30, | 10,567 | 16,391 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

OHIO POWER COMPANY CONSOLIDATED
INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF
REGISTRANT SUBSIDIARIES

The condensed notes to OPCo's condensed consolidated financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to OPCo. The footnotes begin on page 156.

| | Footnote Reference |
|--|-----------------------|
| Significant Accounting Matters | Note 1 |
| New Accounting Pronouncements and Extraordinary Item | Note 2 |
| Rate Matters | Note 3 |
| Commitments, Guarantees and Contingencies | Note 4 |
| Benefit Plans | Note 6 |
| Business Segments | Note 7 |
| Derivatives and Hedging | Note 8 |
| Fair Value Measurements | Note 9 |
| Income Taxes | Note 10 |
| Financing Activities | Note 11 |
| Cost Reduction Initiatives | Note 12 |

PUBLIC SERVICE COMPANY OF OKLAHOMA

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PUBLIC SERVICE COMPANY OF OKLAHOMA
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

RESULTS OF OPERATIONS

Second Quarter of 2010 Compared to Second Quarter of 2009

Reconciliation of Second Quarter of 2009 to Second Quarter of 2010
Net Income
(in millions)

| | |
|---------------------------------|-------|
| Second Quarter of 2009 | \$ 24 |
| Changes in Gross Margin: | |
| Retail Margins (a) | 12 |
| Other Revenues | (2) |
| Total Change in Gross Margin | 10 |
| Total Expenses and Other: | |
| Other Operation and Maintenance | (23) |
| Depreciation and Amortization | 2 |
| Other Income | (2) |
| Interest Expense | (1) |
| Total Expenses and Other | (24) |
| Income Tax Expense | 5 |
| Second Quarter of 2010 | \$ 15 |

(a) Includes firm wholesale sales to municipals and cooperatives.

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins increased \$12 million primarily due to the following:
 - An \$8 million increase primarily resulting from rate increases during the year, including revenue increases from rate riders of \$5 million. This increase in retail margins had corresponding offsets of \$2 million related to cost recovery riders/trackers that were recognized in other expense line items below.
 - A \$4 million increase in weather-related usage primarily due to a 17% increase in cooling degree days.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses increased \$23 million primarily due to expenses related to the cost reduction initiatives in the second quarter of 2010.
- Income Tax Expense decreased \$5 million primarily due to a decrease in pretax book income.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009

Reconciliation of Six Months Ended June 30, 2009 to Six Months Ended June 30, 2010

Net Income
(in millions)

| | | |
|---------------------------------|----|------|
| Six Months Ended June 30, 2009 | \$ | 30 |
| Changes in Gross Margin: | | |
| Retail Margins (a) | | 23 |
| Transmission Revenues | | 3 |
| Other Revenues | | (1) |
| Total Change in Gross Margin | | 25 |
| Total Expenses and Other: | | |
| Other Operation and Maintenance | | (39) |
| Depreciation and Amortization | | 2 |
| Taxes Other Than Income Taxes | | 1 |
| Other Income | | (2) |
| Interest Expense | | (3) |
| Total Expenses and Other | | (41) |
| Income Tax Expense | | 6 |
| Six Months Ended June 30, 2010 | \$ | 20 |

(a) Includes firm wholesale sales to municipalities and cooperatives.

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins increased \$23 million primarily due to the following:
 - A \$19 million increase primarily resulting from rate increases during the year, including revenue increases from rate riders of \$12 million. This increase in retail margins had corresponding offsets of \$4 million related to cost recovery riders/trackers that were recognized in other expense line items below.
 - A \$10 million increase in weather-related usage primarily due to a 27% increase in heating degree days and a 14% increase in cooling degree days.
- Transmission Revenues increased \$3 million primarily due to higher rates in the SPP region.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses increased \$39 million primarily due to the following:
 - A \$23 million increase primarily due to expenses related to the cost reduction initiatives in the second quarter of 2010.
 - A \$6 million increase in employee-related expenses.
 - A \$5 million increase in plant maintenance expense resulting from the 2009 deferral of generation maintenance expenses as a result of PSO's base

rate case.

- Interest Expense increased \$3 million primarily due to an increase in long-term borrowings in the last half of 2009.
- Income Tax Expense decreased \$6 million primarily due to a decrease in pretax book income.

FINANCIAL CONDITION

LIQUIDITY

PSO participates in the Utility Money Pool, which provides access to AEP's liquidity. PSO relies upon ready access to capital markets, cash flows from operations and access to the Utility Money Pool to fund current operations and capital expenditures. See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page 224 for additional discussion of liquidity.

Credit Ratings

Downgrades in credit ratings by one of the rating agencies could increase PSO's borrowing costs.

CASH FLOW

Cash flows for the six months ended June 30, 2010 and 2009 were as follows:

| | 2010 | 2009 |
|--|----------------|-----------|
| | (in thousands) | |
| Cash and Cash Equivalents at Beginning of Period | \$ 796 | \$ 1,345 |
| Net Cash Flows from Operating Activities | 8,473 | 199,675 |
| Net Cash Flows Used for Investing Activities | (46,697) | (118,301) |
| Net Cash Flows from (Used For) Financing Activities | 38,517 | (81,659) |
| Net Increase (Decrease) in Cash and Cash Equivalents | 293 | (285) |
| Cash and Cash Equivalents at End of Period | \$ 1,089 | \$ 1,060 |

Operating Activities

Net Cash Flows from Operating Activities were \$8 million in 2010. PSO produced Net Income of \$20 million during the period and had noncash expense items of \$54 million for Depreciation and Amortization and \$33 million for Deferred Income Taxes, partially offset by a \$19 million increase in the deferral of Property Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a \$38 million inflow from Accounts Payable primarily due to timing differences for payments to affiliates and purchased power. The \$100 million outflow from Fuel Over/Under-Recovery, Net was the result of higher fuel costs in relation to commission-approved fuel recovery rates.

Net Cash Flows from Operating Activities were \$200 million in 2009. PSO produced Net Income of \$30 million during the period and had a noncash expense item of \$56 million for Depreciation and Amortization, partially offset by a \$19 million increase in the deferral of Property Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The \$88 million inflow from Accounts Receivable, Net was primarily due to receiving the SIA refund from the AEP East companies and lower customer receivables. The \$40 million inflow from Accrued Taxes, Net was the result of increased accruals related to property and income taxes. The \$15 million inflow from Fuel Over/Under-Recovery, Net was primarily due to lower fuel costs, partially offset by SIA refunds to customers.

Investing Activities

Net Cash Flows Used for Investing Activities during 2010 and 2009 were \$47 million and \$118 million, respectively. Construction Expenditures of \$107 million and \$99 million in 2010 and 2009, respectively, were primarily related to project improvements made during the restoration of damage from a 2010 ice storm and for improved generation, transmission and distribution service reliability. During 2010, PSO had a net decrease of \$63 million in loans to the Utility Money Pool. During 2009, PSO had a net increase of \$19 million in loans to the Utility Money Pool.

Financing Activities

Net Cash Flows from Financing Activities were \$39 million during 2010. PSO had a net increase of \$66 million in borrowings from the Utility Money Pool. This inflow was partially offset by \$25 million paid in dividends on common stock.

Net Cash Flows Used for Financing Activities were \$82 million during 2009. PSO had a net decrease of \$70 million in borrowings from the Utility Money Pool. PSO retired \$50 million of Senior Unsecured Notes in June 2009 and issued \$34 million of Pollution Control Bonds in February 2009. PSO received capital contributions from the Parent of \$20 million. In addition, PSO paid \$15 million in dividends on common stock.

PSO did not have any long-term debt issuances or retirements during the first six months of 2010.

SUMMARY OBLIGATION INFORMATION

A summary of contractual obligations is included in the 2009 Annual Report and has not changed significantly from year-end.

REGULATORY ACTIVITY

Oklahoma Regulatory Activity

In July 2010, PSO filed a request with the OCC to increase annual base rates by \$82 million, including \$30 million that is currently being recovered through a rider. The requested increase is based on an 11.5% return on common equity. PSO requested that new rates become effective no later than July 2011. A procedural schedule has not been established. See “2010 Oklahoma Base Rate Case” section of Note 3.

SIGNIFICANT FACTORS

LITIGATION AND ENVIRONMENTAL ISSUES

In the ordinary course of business, PSO is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual resolution will be or the timing and amount of any loss, fine or penalty may be. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2009 Annual Report. Also, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 156. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

See the “Significant Factors” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” section beginning on page 224 for additional discussion of relevant factors.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the “Critical Accounting Policies and Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” in the 2009 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets and pension and other postretirement benefits.

See the “New Accounting Pronouncements” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” beginning on page 224 for a discussion of the adoption and impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

See “Quantitative And Qualitative Disclosures About Risk Management Activities” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” beginning on page 224 for a discussion of risk management activities.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2010 and 2009
(in thousands)
(Unaudited)

| | Three Months Ended | | Six Months Ended | |
|---|--------------------|-----------------|------------------|-----------------|
| | 2010 | 2009 | 2010 | 2009 |
| REVENUES | | | | |
| Electric Generation, Transmission and Distribution | \$322,394 | \$263,763 | \$550,945 | \$542,534 |
| Sales to AEP Affiliates | 4,481 | 11,690 | 13,151 | 27,513 |
| Other Revenues | 811 | 1,688 | 1,345 | 2,381 |
| TOTAL REVENUES | 327,686 | 277,141 | 565,441 | 572,428 |
| EXPENSES | | | | |
| Fuel and Other Consumables Used for Electric Generation | 88,615 | 62,753 | 129,587 | 182,152 |
| Purchased Electricity for Resale | 53,555 | 46,108 | 98,535 | 90,533 |
| Purchased Electricity from AEP Affiliates | 10,471 | 3,416 | 21,463 | 9,331 |
| Other Operation | 70,837 | 46,521 | 120,499 | 86,066 |
| Maintenance | 27,038 | 27,965 | 57,977 | 53,395 |
| Depreciation and Amortization | 26,920 | 28,529 | 54,208 | 56,479 |
| Taxes Other Than Income Taxes | 10,985 | 10,958 | 21,285 | 21,709 |
| TOTAL EXPENSES | 288,421 | 226,250 | 503,554 | 499,665 |
| OPERATING INCOME | 39,265 | 50,891 | 61,887 | 72,763 |
| Other Income (Expense): | | | | |
| Interest Income | 93 | 580 | 275 | 1,228 |
| Carrying Costs Income | 819 | 1,019 | 1,686 | 2,730 |
| Allowance for Equity Funds Used During Construction | 119 | 571 | 366 | 741 |
| Interest Expense | (15,765) | (15,163) | (33,128) | (29,968) |
| INCOME BEFORE INCOME TAX EXPENSE | 24,531 | 37,898 | 31,086 | 47,494 |
| Income Tax Expense | 9,042 | 13,776 | 11,458 | 17,334 |
| NET INCOME | 15,489 | 24,122 | 19,628 | 30,160 |
| Preferred Stock Dividend Requirements | 49 | 53 | 103 | 106 |
| EARNINGS ATTRIBUTABLE TO COMMON STOCK | \$15,440 | \$24,069 | \$19,525 | \$30,054 |

The common stock of PSO is wholly-owned by AEP.

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME (LOSS)

For the Six Months Ended June 30, 2010 and 2009

(in thousands)

(Unaudited)

| | Common Stock | Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
|--|-----------------|--------------------|----------------------|--|------------|
| TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2008 | \$ 157,230 | \$ 340,016 | \$ 251,704 | \$ (704) | \$ 748,246 |
| Capital Contribution from Parent | | 20,000 | | | 20,000 |
| Common Stock Dividends | | | (14,500) | | (14,500) |
| Preferred Stock Dividends | | | (106) | | (106) |
| Gain on Reacquired Preferred Stock | | 1 | | | 1 |
| Other Change in Common Shareholder's Equity | | 4,214 | (4,214) | | - |
| SUBTOTAL – COMMON SHAREHOLDER'S EQUITY | | | | | 753,641 |
| COMPREHENSIVE INCOME | | | | | |
| Other Comprehensive Income, Net of Taxes: | | | | | |
| Cash Flow Hedges, Net of Tax of \$117 | | | | 218 | 218 |
| NET INCOME | | | 30,160 | | 30,160 |
| TOTAL COMPREHENSIVE INCOME | | | | | 30,378 |
| TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2009 | \$ 157,230 | \$ 364,231 | \$ 263,044 | \$ (486) | \$ 784,019 |
| TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2009 | \$ 157,230 | \$ 364,231 | \$ 290,880 | \$ (599) | \$ 811,742 |
| Common Stock Dividends | | | (25,375) | | (25,375) |
| Preferred Stock Dividends | | | (103) | | (103) |
| Gain on Reacquired Preferred Stock | | 76 | | | 76 |
| SUBTOTAL – COMMON SHAREHOLDER'S EQUITY | | | | | 786,340 |
| COMPREHENSIVE INCOME | | | | | |
| Other Comprehensive Income, Net of Taxes: | | | | | |
| Cash Flow Hedges, Net of Tax of \$39 | | | | 72 | 72 |
| NET INCOME | | | 19,628 | | 19,628 |
| TOTAL COMPREHENSIVE INCOME | | | | | 19,700 |

TOTAL COMMON SHAREHOLDER'S

| | | | | | |
|------------------------|------------|------------|------------|---------|--------------|
| EQUITY – JUNE 30, 2010 | \$ 157,230 | \$ 364,307 | \$ 285,030 | \$ (527 |) \$ 806,040 |
|------------------------|------------|------------|------------|---------|--------------|

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS

June 30, 2010 and December 31, 2009

(in thousands)

(Unaudited)

| | 2010 | 2009 |
|--|--------------------|--------------------|
| CURRENT ASSETS | | |
| Cash and Cash Equivalents | \$1,089 | \$796 |
| Advances to Affiliates | - | 62,695 |
| Accounts Receivable: | | |
| Customers | 40,145 | 38,239 |
| Affiliated Companies | 58,673 | 59,096 |
| Miscellaneous | 7,388 | 7,242 |
| Allowance for Uncollectible Accounts | (144) | (304) |
| Total Accounts Receivable | 106,062 | 104,273 |
| Fuel | 22,270 | 20,892 |
| Materials and Supplies | 46,816 | 44,914 |
| Risk Management Assets | 2,608 | 2,376 |
| Deferred Income Tax Benefits | 8,771 | 26,335 |
| Accrued Tax Benefits | 29,754 | 15,291 |
| Regulatory Asset for Under-Recovered Fuel Costs | 48,689 | - |
| Prepayments and Other Current Assets | 6,329 | 9,139 |
| TOTAL CURRENT ASSETS | 272,388 | 286,711 |
| PROPERTY, PLANT AND EQUIPMENT | | |
| Electric: | | |
| Production | 1,319,083 | 1,300,069 |
| Transmission | 658,014 | 617,291 |
| Distribution | 1,652,722 | 1,596,355 |
| Other Property, Plant and Equipment | 244,748 | 228,705 |
| Construction Work in Progress | 36,359 | 67,138 |
| Total Property, Plant and Equipment | 3,910,926 | 3,809,558 |
| Accumulated Depreciation and Amortization | 1,237,130 | 1,220,177 |
| TOTAL PROPERTY, PLANT AND EQUIPMENT – NET | 2,673,796 | 2,589,381 |
| OTHER NONCURRENT ASSETS | | |
| Regulatory Assets | 272,732 | 279,185 |
| Long-term Risk Management Assets | 33 | 50 |
| Deferred Charges and Other Noncurrent Assets | 31,268 | 13,880 |
| TOTAL OTHER NONCURRENT ASSETS | 304,033 | 293,115 |
| TOTAL ASSETS | \$3,250,217 | \$3,169,207 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
June 30, 2010 and December 31, 2009
(Unaudited)

| | 2010 | 2009 |
|--|----------------|-------------|
| | (in thousands) | |
| CURRENT LIABILITIES | | |
| Advances from Affiliates | \$66,229 | \$- |
| Accounts Payable: | | |
| General | 89,124 | 76,895 |
| Affiliated Companies | 98,320 | 71,099 |
| Long-term Debt Due Within One Year – Nonaffiliated | 75,000 | - |
| Risk Management Liabilities | 387 | 2,579 |
| Customer Deposits | 41,015 | 42,002 |
| Accrued Taxes | 38,171 | 19,471 |
| Regulatory Liability for Over-Recovered Fuel Costs | - | 51,087 |
| Other Current Liabilities | 59,620 | 60,905 |
| TOTAL CURRENT LIABILITIES | 467,866 | 324,038 |
| NONCURRENT LIABILITIES | | |
| Long-term Debt – Nonaffiliated | 893,851 | 968,121 |
| Long-term Risk Management Liabilities | 112 | 144 |
| Deferred Income Taxes | 610,292 | 588,768 |
| Regulatory Liabilities and Deferred Investment Tax Credits | 317,960 | 326,931 |
| Employee Benefits and Pension Obligations | 105,939 | 107,748 |
| Deferred Credits and Other Noncurrent Liabilities | 43,275 | 36,457 |
| TOTAL NONCURRENT LIABILITIES | 1,971,429 | 2,028,169 |
| TOTAL LIABILITIES | 2,439,295 | 2,352,207 |
| Cumulative Preferred Stock Not Subject to Mandatory Redemption | 4,882 | 5,258 |
| Rate Matters (Note 3) | | |
| Commitments and Contingencies (Note 4) | | |
| COMMON SHAREHOLDER’S EQUITY | | |
| Common Stock – Par Value – \$15 Per Share: | | |
| Authorized – 11,000,000 Shares | | |
| Issued – 10,482,000 Shares | | |
| Outstanding – 9,013,000 Shares | 157,230 | 157,230 |
| Paid-in Capital | 364,307 | 364,231 |
| Retained Earnings | 285,030 | 290,880 |
| Accumulated Other Comprehensive Income (Loss) | (527) | (599) |
| TOTAL COMMON SHAREHOLDER’S EQUITY | 806,040 | 811,742 |
| TOTAL LIABILITIES AND SHAREHOLDERS’ EQUITY | \$3,250,217 | \$3,169,207 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2010 and 2009
(in thousands)
(Unaudited)

| | 2010 | 2009 |
|--|-----------|-----------|
| OPERATING ACTIVITIES | | |
| Net Income | \$ 19,628 | \$ 30,160 |
| Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities: | | |
| Depreciation and Amortization | 54,208 | 56,479 |
| Deferred Income Taxes | 33,402 | (6,130) |
| Carrying Costs Income | (1,686) | (2,730) |
| Allowance for Equity Funds Used During Construction | (366) | (741) |
| Mark-to-Market of Risk Management Contracts | (2,448) | 1,053 |
| Property Taxes | (18,532) | (18,700) |
| Fuel Over/Under-Recovery, Net | (99,776) | 15,268 |
| Change in Other Noncurrent Assets | (13,891) | 1,885 |
| Change in Other Noncurrent Liabilities | 2,900 | (3,290) |
| Changes in Certain Components of Working Capital: | | |
| Accounts Receivable, Net | (1,789) | 87,923 |
| Fuel, Materials and Supplies | (3,280) | 4,322 |
| Accounts Payable | 37,817 | 7,980 |
| Accrued Taxes, Net | 4,838 | 39,800 |
| Other Current Assets | 2,760 | 115 |
| Other Current Liabilities | (5,312) | (13,719) |
| Net Cash Flows from Operating Activities | 8,473 | 199,675 |
| INVESTING ACTIVITIES | | |
| Construction Expenditures | (107,213) | (98,559) |
| Change in Advances to Affiliates, Net | 62,695 | (19,438) |
| Other Investing Activities | (2,179) | (304) |
| Net Cash Flows Used for Investing Activities | (46,697) | (118,301) |
| FINANCING ACTIVITIES | | |
| Capital Contribution from Parent | - | 20,000 |
| Issuance of Long-term Debt – Nonaffiliated | - | 33,283 |
| Change in Advances from Affiliates, Net | 66,229 | (70,308) |
| Retirement of Long-term Debt – Nonaffiliated | - | (50,000) |
| Retirement of Cumulative Preferred Stock | (301) | (2) |
| Principal Payments for Capital Lease Obligations | (2,040) | (772) |
| Dividends Paid on Common Stock | (25,375) | (14,500) |
| Dividends Paid on Cumulative Preferred Stock | (103) | (106) |
| Other Financing Activities | 107 | 746 |
| Net Cash Flows from (Used For) Financing Activities | 38,517 | (81,659) |
| Net Increase (Decrease) in Cash and Cash Equivalents | 293 | (285) |
| Cash and Cash Equivalents at Beginning of Period | 796 | 1,345 |

| | | | | |
|--|----|-------|----|-------|
| Cash and Cash Equivalents at End of Period | \$ | 1,089 | \$ | 1,060 |
|--|----|-------|----|-------|

| SUPPLEMENTARY INFORMATION | | | | |
|--|----|---------|----|--------|
| Cash Paid for Interest, Net of Capitalized Amounts | \$ | 30,152 | \$ | 44,038 |
| Net Cash Paid (Received) for Income Taxes | | (8,073) | | 3,584 |
| Noncash Acquisitions Under Capital Leases | | 13,434 | | 522 |
| Construction Expenditures Included in Accounts Payable at June 30, | | 13,534 | | 5,932 |

| | | | | |
|--|----|---------|----|--------|
| Cash Paid for Interest, Net of Capitalized Amounts | \$ | 30,152 | \$ | 44,038 |
| Net Cash Paid (Received) for Income Taxes | | (8,073) | | 3,584 |
| Noncash Acquisitions Under Capital Leases | | 13,434 | | 522 |
| Construction Expenditures Included in Accounts Payable at June 30, | | 13,534 | | 5,932 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

PUBLIC SERVICE COMPANY OF OKLAHOMA
INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF
REGISTRANT SUBSIDIARIES

The condensed notes to PSO's condensed consolidated financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to PSO. The footnotes begin on page 156.

| | Footnote Reference |
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| Significant Accounting Matters | Note 1 |
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SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

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SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

RESULTS OF OPERATIONS

Second Quarter of 2010 Compared to Second Quarter of 2009

Reconciliation of Second Quarter of 2009 to Second Quarter of 2010
Income Before Extraordinary Loss
(in millions)

| | | |
|---|-----|----|
| Second Quarter of 2009 | \$ | 36 |
| Changes in Gross Margin: | | |
| Retail Margins (a) | | 25 |
| Transmission Revenues | (1 |) |
| Other Revenues | (7 |) |
| Total Change in Gross Margin | | 17 |
| Total Expenses and Other: | | |
| Other Operation and Maintenance | (28 |) |
| Depreciation and Amortization | 6 | |
| Interest Expense | (3 |) |
| Equity Earnings of Unconsolidated Subsidiaries | 1 | |
| Total Expenses and Other | (24 |) |
| Income Tax Expense | (2 |) |
| Second Quarter of 2010 | \$ | 27 |

(a) Includes firm wholesale sales to municipalities and cooperatives.

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins increased \$25 million primarily due to:
 - A \$9 million increase in base rates in Arkansas and Texas.
 - A \$6 million increase in weather-related usage primarily due to a 30% increase in cooling degree days.
 - A \$4 million increase in industrial sales due to higher usage reflecting an improvement in demand.
 - A \$4 million increase in fuel recovery primary due to lower capacity costs.
- Other Revenues decreased \$7 million resulting from the deconsolidation of SWEPCo's mining subsidiary, DHLC. Prior to the deconsolidation, SWEPCo recorded revenues from coal deliveries from DHLC to CLECO. SWEPCo prospectively adopted the "Consolidation" accounting guidance effective January 1, 2010 and began accounting for DHLC under the equity method of accounting. The decreased revenue from coal deliveries was partially offset by a corresponding decrease in Other Operation and Maintenance expenses from

mining operations as discussed below.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses increased \$28 million primarily due to:
 - A \$29 million increase due to expenses related to the cost reduction initiatives in the second quarter of 2010.
 - A \$5 million increase in other generation operation expenses primarily related to Stall Unit testing for commercial operation. The Stall Unit was placed in service in June 2010.
- These increases were partially offset by:
- A \$5 million decrease in expenses for coal deliveries from SWEPCo's mining subsidiary, DHLC. The decreased expenses for coal deliveries were partially offset by a corresponding decrease in revenues from mining operations as discussed above.
 - Depreciation and Amortization expenses decreased \$6 million primarily due to lower Arkansas and Texas depreciation resulting from the Arkansas and Texas base rate orders.
 - Interest Expense increased \$3 million primarily due to increased long-term debt outstanding and capital leases, partially offset by an increase in the debt component of AFUDC due to the Turk Plant and Stall Unit generation projects.
 - Income Tax Expense increased \$2 million primarily due to changes in certain book/tax differences accounted for on a flow-through basis, partially offset by a decrease in pretax book income.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009

Reconciliation of Six Months Ended June 30, 2009 to Six Months Ended June 30, 2010

Income Before Extraordinary Loss

(in millions)

| | | |
|--|---|------|
| Six Months Ended June 30, 2009 | \$ | 47 |
| Changes in Gross Margin: | | |
| Retail Margins (a) | | 43 |
| Off-system Sales | | 1 |
| Transmission Revenues | | 1 |
| Other Revenues | | (18) |
| Total Change in Gross Margin | | 27 |
| Total Expenses and Other: | | |
| Other Operation and Maintenance | | (22) |
| Depreciation and Amortization | | 9 |
| Taxes Other Than Income Taxes | | (1) |
| Other Income | | 10 |
| Interest Expense | | (5) |
| Equity Earnings of Unconsolidated Subsidiaries | | 1 |
| Total Expenses and Other | | (8) |
| Income Tax Expense | | (8) |
| Six Months Ended June 30, 2010 | \$ | 58 |
| (a) | Includes firm wholesale sales to municipals and cooperatives. | |

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- Retail Margins increased \$43 million primarily due to:
 - A \$13 million increase in base rates in Arkansas and Texas.
 - A \$13 million increase in weather-related usage primarily due to a 42% increase in heating degree days.
 - A \$6 million increase in industrial sales due to higher usage reflecting an improvement in demand.
 - A \$5 million increase in fuel recovery primarily due to lower capacity costs.
- Other Revenues decreased \$18 million resulting from the deconsolidation of SWEPCo's mining subsidiary, DHLHC. Prior to the deconsolidation, SWEPCo recorded revenues from coal deliveries from DHLHC to CLECO. SWEPCo prospectively adopted the "Consolidation" accounting guidance effective January 1, 2010 and began accounting for DHLHC under the equity method of accounting. The decreased revenue from coal deliveries was partially offset by a corresponding decrease in Other Operation and Maintenance expenses from mining operations as discussed below.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- Other Operation and Maintenance expenses increased \$22 million primarily due to:
 - A \$29 million increase due to expenses related to the cost reduction initiatives in the second quarter of 2010.
 - A \$3 million increase in employee-related expenses.
 - A \$2 million gain on sale of property during the first quarter of 2009 related to the sale of percentage ownership of Turk Plant to nonaffiliated companies who exercised their participation options.

These increases were partially offset by:

- A \$13 million decrease in expenses for coal deliveries from SWEPCo's mining subsidiary, DHLC. The decreased expenses for coal deliveries were partially offset by a corresponding decrease in revenues from mining operations as discussed above.
- Depreciation and Amortization expenses decreased \$9 million primarily due to lower Arkansas and Texas depreciation resulting from the Arkansas and Texas base rate orders and the deconsolidation of DHLC.
- Other Income increased \$10 million primarily due to an increase in the equity component of AFUDC as a result of construction at the Turk Plant and Stall Unit and the reapplication of "Regulated Operations" accounting guidance for the generation portion of Texas' retail jurisdiction effective the second quarter of 2009.
- Interest Expense increased \$5 million primarily due to increased long-term debt outstanding and capital leases, partially offset by an increase in the debt component of AFUDC due to the Turk Plant and Stall Unit generation projects.
- Income Tax Expense increased \$8 million primarily due to an increase in pretax book income.

FINANCIAL CONDITION

LIQUIDITY

SWEPCo participates in the Utility Money Pool, which provides access to AEP's liquidity. SWEPCo relies upon ready access to capital markets, cash flows from operations and access to the Utility Money Pool to fund current operations and capital expenditures. See the "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page 224 for additional discussion of liquidity.

Credit Ratings

In June 2010, Fitch downgraded SWEPCo's senior unsecured rating to BBB. Further downgrades in SWEPCo's ratings by one of the rating agencies could increase SWEPCo's borrowing costs and affect SWEPCo's ability to finance construction costs.

CASH FLOW

Cash flows for the six months ended June 30, 2010 and 2009 were as follows:

| | 2010 | 2009 |
|--|----------------|-----------|
| | (in thousands) | |
| Cash and Cash Equivalents at Beginning of Period | \$ 1,661 | \$ 1,910 |
| Net Cash Flows from Operating Activities | 80,809 | 222,403 |
| Net Cash Flows Used for Investing Activities | (371,560) | (236,343) |
| Net Cash Flows from Financing Activities | 290,652 | 13,541 |
| Net Decrease in Cash and Cash Equivalents | (99) | (399) |

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| | | |
|--|----------|----------|
| Cash and Cash Equivalents at End of Period | \$ 1,562 | \$ 1,511 |
|--|----------|----------|

Operating Activities

Net Cash Flows from Operating Activities were \$81 million in 2010. SWEPCo produced Net Income of \$58 million during the period and had a noncash item of \$63 million for Depreciation and Amortization, partially offset by \$28 million for Allowance for Equity Funds Used During Construction and an \$18 million increase in the deferral of Property Taxes. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The \$32 million inflow from Accrued Taxes, Net was the result of an increase in accruals related to property taxes. The \$25 million outflow from Accounts Receivable, Net was primarily due to increased affiliated and jointly owned receivables partially offset by lower construction related receivables. The \$20 million inflow from Fuel, Materials and Supplies was primarily due to a decrease in coal and lignite inventories. The \$16 million outflow from Fuel Over/Under-Recovery, Net was the result of higher fuel costs in relation to commission-approved fuel recovery rates in Texas.

Net Cash Flows from Operating Activities were \$222 million in 2009. SWEPCo produced Net Income of \$42 million during the period and had a noncash item of \$72 million for Depreciation and Amortization, partially offset by \$30 million for Deferred Income Taxes, a \$20 million increase in the deferral of Property Taxes and \$19 million for Allowance for Equity Funds Used During Construction. The other changes in assets and liabilities represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. The activity in working capital relates to a number of items. The \$88 million inflow from Accounts Receivable, Net was primarily due to the receipt of payment for SIA from the AEP East companies. The \$64 million inflow from Accrued Taxes, Net was the result of an increase in accruals related to federal and property taxes. The \$54 million outflow from Other Current Liabilities was due to a decrease in checks outstanding, a refund to wholesale customers for the SIA and payments of employee-related expenses. The \$23 million inflow from Accounts Payable was primarily due to increases related to customer accounts factored, net. The \$44 million inflow from Fuel Over/Under-Recovery, Net was the result of a decrease in fuel costs in relation to the recovery of these costs from customers.

Investing Activities

Net Cash Flows Used for Investing Activities during 2010 and 2009 were \$372 million and \$236 million, respectively. Construction Expenditures of \$176 million and \$306 million in 2010 and 2009, respectively, were primarily related to new generation projects at the Turk Plant and Stall Unit. Proceeds from Sales of Assets in 2009 primarily included \$104 million relating to the sale of a portion of Turk Plant to joint owners. SWEPCo's net increase in loans to the Utility Money Pool during 2010 and 2009 were \$193 million and \$32 million, respectively.

Financing Activities

Net Cash Flows from Financing Activities were \$291 million during 2010 related to a \$350 million issuance of Senior Unsecured Notes and a \$54 million issuance of Pollution Control Bonds. These increases were partially offset by a \$54 million retirement of Pollution Control Bonds and a \$50 million retirement of Notes Payable – Affiliated.

Net Cash Flows from Financing Activities were \$14 million during 2009. SWEPCo received capital contributions from the Parent of \$18 million and paid \$5 million in principal payments for capital lease obligations.

Long-term debt issuances and retirements during the first six months of 2010 were:

Issuances

| Type of Debt | Principal Amount (in thousands) | Interest Rate (%) | Due Date |
|-------------------------|------------------------------------|----------------------|----------|
| Senior Unsecured Notes | \$ 350,000 | 6.20 | 2040 |
| Pollution Control Bonds | 53,500 | 3.25 | 2015 |

Retirements

| Type of Debt | Principal Amount Paid (in thousands) | Interest Rate (%) | Due Date |
|----------------------------|---|----------------------|----------|
| Notes Payable – Affiliated | \$ 50,000 | 4.45 | 2010 |
| Pollution Control Bonds | 53,500 | Variable | 2019 |

SUMMARY OBLIGATION INFORMATION

A summary of contractual obligations is included in the 2009 Annual Report and has not changed significantly from year-end other than debt issuances and retirements discussed in “Cash Flow” above.

REGULATORY ACTIVITY

Texas Regulatory Activity

In April 2010, a settlement agreement was approved by the PUCT to increase SWEPCo’s base rates by approximately \$15 million annually, effective May 2010, including a return on equity of 10.33%. In addition, the settlement agreement allows SWEPCo a \$10 million one-year surcharge rider to recover additional vegetation management costs that SWEPCo must spend within two years. See “2009 Texas Base Rate Filing” section of Note 3.

SIGNIFICANT FACTORS

REGULATORY ISSUES

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which is expected to be in-service in 2012. SWEPCo owns 73% of the Turk Plant and will operate the completed facility. The Turk Plant is currently estimated to cost \$1.7 billion, excluding AFUDC, plus an additional \$131 million for transmission, excluding AFUDC. SWEPCo’s share is currently estimated to cost \$1.3 billion, excluding AFUDC, plus an additional \$131 million for transmission, excluding AFUDC. Notices of appeal are outstanding at the Arkansas Court of Appeals and the Circuit Court of Hempstead County, Arkansas. Matters are also outstanding at the LPSC, the Texas Court of Appeals and the Federal District Court for the Western District of Arkansas. See “Turk Plant” section of Note 3.

LITIGATION AND ENVIRONMENTAL ISSUES

In the ordinary course of business SWEPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual resolution will be or the timing and amount of any loss, fine or penalty may be. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies in the 2009 Annual Report. Also, see Note 3 – Rate Matters and Note 4 – Commitments, Guarantees and Contingencies within the Condensed Notes to Condensed Financial Statements beginning on page 156. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

See the “Significant Factors” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” section beginning on page 224 for additional discussion of relevant factors.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

See the “Critical Accounting Policies and Estimates” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” in the 2009 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, the valuation of long-lived assets and pension and other postretirement benefits.

See the “New Accounting Pronouncements” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” beginning on page 224 for a discussion of the adoption and impact of new accounting pronouncements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

See “Quantitative And Qualitative Disclosures About Risk Management Activities” section of “Combined Management’s Discussion and Analysis of Registrant Subsidiaries” beginning on page 224 for a discussion of risk management activities.

**SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME**

For the Three and Six Months Ended June 30, 2010 and 2009

(in thousands)

(Unaudited)

| | Three Months Ended | | Six Months Ended | |
|---|--------------------|-----------------|------------------|-----------------|
| | 2010 | 2009 | 2010 | 2009 |
| REVENUES | | | | |
| Electric Generation, Transmission and Distribution | \$347,657 | \$326,992 | \$680,735 | \$629,375 |
| Sales to AEP Affiliates | 13,231 | 5,706 | 22,564 | 14,050 |
| Lignite Revenues – Nonaffiliated | - | 7,518 | - | 18,238 |
| Other Revenues | 579 | 566 | 972 | 921 |
| TOTAL REVENUES | 361,467 | 340,782 | 704,271 | 662,584 |
| EXPENSES | | | | |
| Fuel and Other Consumables Used for Electric Generation | 135,051 | 117,135 | 257,939 | 243,450 |
| Purchased Electricity for Resale | 22,841 | 30,339 | 64,727 | 54,736 |
| Purchased Electricity from AEP Affiliates | 4,211 | 10,520 | 13,963 | 23,530 |
| Other Operation | 82,265 | 59,566 | 140,518 | 113,770 |
| Maintenance | 28,133 | 23,314 | 45,552 | 50,016 |
| Depreciation and Amortization | 29,868 | 35,559 | 63,111 | 72,351 |
| Taxes Other Than Income Taxes | 15,580 | 15,479 | 31,475 | 30,868 |
| TOTAL EXPENSES | 317,949 | 291,912 | 617,285 | 588,721 |
| OPERATING INCOME | 43,518 | 48,870 | 86,986 | 73,863 |
| Other Income (Expense): | | | | |
| Interest Income | 169 | 363 | 248 | 817 |
| Allowance for Equity Funds Used During Construction | 12,462 | 12,369 | 27,979 | 18,774 |
| Interest Expense | (21,475) | (18,990) | (40,019) | (35,289) |
| INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS | 34,674 | 42,612 | 75,194 | 58,165 |
| Income Tax Expense | 8,707 | 6,834 | 18,863 | 10,687 |
| Equity Earnings of Unconsolidated Subsidiaries | 738 | - | 1,457 | - |
| INCOME BEFORE EXTRAORDINARY LOSS | 26,705 | 35,778 | 57,788 | 47,478 |
| EXTRAORDINARY LOSS, NET OF TAX | - | (5,325) | - | (5,325) |
| NET INCOME | 26,705 | 30,453 | 57,788 | 42,153 |
| Less: Net Income Attributable to Noncontrolling Interest | 1,273 | 812 | 2,424 | 1,949 |
| NET INCOME ATTRIBUTABLE TO SWEPCo SHAREHOLDERS | 25,432 | 29,641 | 55,364 | 40,204 |

| | | | | |
|---|----------|----------|----------|----------|
| Less: Preferred Stock Dividend Requirements | 57 | 57 | 114 | 114 |
| EARNINGS ATTRIBUTABLE TO SWEPCo COMMON | | | | |
| SHAREHOLDER | \$25,375 | \$29,584 | \$55,250 | \$40,090 |

The common stock of SWEPCo is wholly-owned by AEP.

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
EQUITY AND COMPREHENSIVE INCOME (LOSS)

For the Six Months Ended June 30, 2010 and 2009

(in thousands)

(Unaudited)

SWEPCo Common Shareholder

| | Common Stock | Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Noncontrolling Interest | Total |
|---|-----------------|--------------------|----------------------|---|----------------------------|--------------|
| TOTAL EQUITY – DECEMBER 31, 2008 | \$ 135,660 | \$ 530,003 | \$ 615,110 | \$ (32,120) | \$ 276 | \$ 1,248,929 |
| Capital Contribution from Parent | | 17,500 | | | | 17,500 |
| Common Stock Dividends – Nonaffiliated | | | | | (1,920) | (1,920) |
| Preferred Stock Dividends | | | (114) | | | (114) |
| Other Changes in Equity | | 2,476 | (2,476) | | | - |
| SUBTOTAL – EQUITY | | | | | | 1,264,395 |
| COMPREHENSIVE INCOME | | | | | | |
| Other Comprehensive Income, Net of Taxes: | | | | | | |
| Cash Flow Hedges, Net of Tax of \$306 | | | | 568 | | 568 |
| Amortization of Pension and OPEB Deferred Costs, Net of Tax of \$8,583 | | | | 15,939 | | 15,939 |
| NET INCOME | | | 40,204 | | 1,949 | 42,153 |
| TOTAL COMPREHENSIVE INCOME | | | | | | 58,660 |
| TOTAL EQUITY – JUNE 30, 2009 | \$ 135,660 | \$ 549,979 | \$ 652,724 | \$ (15,613) | \$ 305 | \$ 1,323,055 |
| TOTAL EQUITY – DECEMBER 31, 2009 | \$ 135,660 | \$ 674,979 | \$ 726,478 | \$ (12,991) | \$ 31 | \$ 1,524,157 |
| Common Stock Dividends – Nonaffiliated | | | | | (1,892) | (1,892) |
| Preferred Stock Dividends | | | (114) | | | (114) |

| | | | | | | |
|--|------------|------------|------------|--------------|--------|--------------|
| SUBTOTAL – EQUITY | | | | | | 1,522,151 |
| COMPREHENSIVE INCOME | | | | | | |
| Other Comprehensive Income, Net of Taxes: | | | | | | |
| Cash Flow Hedges, Net of Tax of \$48 | | | | | | |
| | | | | 90 | | 90 |
| Amortization of Pension and OPEB Deferred Costs, Net of Tax of \$253 | | | | | | |
| | | | | 469 | | 469 |
| NET INCOME | | 55,364 | | | 2,424 | 57,788 |
| TOTAL COMPREHENSIVE INCOME | | | | | | 58,347 |
| TOTAL EQUITY – JUNE 30, 2010 | | | | | | |
| | \$ 135,660 | \$ 674,979 | \$ 781,728 | \$ (12,432) | \$ 563 | \$ 1,580,498 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS

ASSETS

June 30, 2010 and December 31, 2009

(in thousands)

(Unaudited)

| | 2010 | 2009 |
|---|--------------------|--------------------|
| CURRENT ASSETS | | |
| Cash and Cash Equivalents | \$1,562 | \$1,661 |
| Advances to Affiliates | 245,253 | 34,883 |
| Accounts Receivable: | | |
| Customers | 26,322 | 46,657 |
| Affiliated Companies | 38,491 | 19,542 |
| Miscellaneous | 26,261 | 9,952 |
| Allowance for Uncollectible Accounts | (378) | (64) |
| Total Accounts Receivable | 90,696 | 76,087 |
| Fuel | | |
| (June 30, 2010 amount includes \$32,452 related to Sabine) | 96,434 | 121,453 |
| Materials and Supplies | 46,205 | 54,484 |
| Risk Management Assets | 2,197 | 3,049 |
| Deferred Income Tax Benefits | 12,707 | 13,820 |
| Accrued Tax Benefits | 15,141 | 16,164 |
| Regulatory Asset for Under-Recovered Fuel Costs | 13,380 | 1,639 |
| Prepayments and Other Current Assets | 21,904 | 20,503 |
| TOTAL CURRENT ASSETS | 545,479 | 343,743 |
| PROPERTY, PLANT AND EQUIPMENT | | |
| Electric: | | |
| Production | 2,263,438 | 1,837,318 |
| Transmission | 904,424 | 870,069 |
| Distribution | 1,465,137 | 1,447,559 |
| Other Property, Plant and Equipment | | |
| (June 30, 2010 amount includes \$226,011 related to Sabine) | 637,520 | 733,310 |
| Construction Work in Progress | 895,663 | 1,176,639 |
| Total Property, Plant and Equipment | 6,166,182 | 6,064,895 |
| Accumulated Depreciation and Amortization | | |
| (June 30, 2010 amount includes \$88,113 related to Sabine) | 2,054,693 | 2,086,333 |
| TOTAL PROPERTY, PLANT AND EQUIPMENT – NET | 4,111,489 | 3,978,562 |
| OTHER NONCURRENT ASSETS | | |
| Regulatory Assets | 288,004 | 268,165 |
| Long-term Risk Management Assets | 49 | 84 |
| Deferred Charges and Other Noncurrent Assets | 93,881 | 49,479 |
| TOTAL OTHER NONCURRENT ASSETS | 381,934 | 317,728 |
| TOTAL ASSETS | \$5,038,902 | \$4,640,033 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
June 30, 2010 and December 31, 2009
(Unaudited)

| | 2010 | 2009 |
|--|----------------|------------|
| | (in thousands) | |
| CURRENT LIABILITIES | | |
| Accounts Payable: | | |
| General | \$ 149,872 | \$ 160,870 |
| Affiliated Companies | 74,433 | 59,818 |
| Short-term Debt – Nonaffiliated | 8,717 | 6,890 |
| Long-term Debt Due Within One Year – Nonaffiliated | - | 4,406 |
| Long-term Debt Due Within One Year – Affiliated | - | 50,000 |
| Risk Management Liabilities | 1,011 | 844 |
| Customer Deposits | 43,238 | 41,269 |
| Accrued Taxes | 53,692 | 24,720 |
| Accrued Interest | 39,958 | 33,179 |
| Obligations Under Capital Leases | 12,557 | 14,617 |
| Regulatory Liability for Over-Recovered Fuel Costs | 9,887 | 13,762 |
| Provision for SIA Refund | 22,358 | 19,307 |
| Other Current Liabilities | 56,476 | 71,781 |
| TOTAL CURRENT LIABILITIES | 472,199 | 501,463 |
| | | |
| NONCURRENT LIABILITIES | | |
| Long-term Debt – Nonaffiliated | 1,769,394 | 1,419,747 |
| Long-term Risk Management Liabilities | 296 | 221 |
| Deferred Income Taxes | 499,528 | 485,936 |
| Regulatory Liabilities and Deferred Investment Tax Credits | 371,511 | 333,935 |
| Asset Retirement Obligations | 49,161 | 60,562 |
| Employee Benefits and Pension Obligations | 121,001 | 125,956 |
| Obligations Under Capital Leases | 116,887 | 134,044 |
| Deferred Credits and Other Noncurrent Liabilities | 53,730 | 49,315 |
| TOTAL NONCURRENT LIABILITIES | 2,981,508 | 2,609,716 |
| | | |
| TOTAL LIABILITIES | 3,453,707 | 3,111,179 |
| | | |
| Cumulative Preferred Stock Not Subject to Mandatory Redemption | 4,697 | 4,697 |
| | | |
| Rate Matters (Note 3) | | |
| Commitments and Contingencies (Note 4) | | |
| | | |
| EQUITY | | |
| Common Stock – Par Value – \$18 Per Share: | | |
| Authorized – 7,600,000 Shares | | |
| Outstanding – 7,536,640 Shares | 135,660 | 135,660 |
| Paid-in Capital | 674,979 | 674,979 |

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| | | |
|---|--------------------|--------------------|
| Retained Earnings | 781,728 | 726,478 |
| Accumulated Other Comprehensive Income (Loss) | (12,432) | (12,991) |
| TOTAL COMMON SHAREHOLDER'S EQUITY | 1,579,935 | 1,524,126 |
| Noncontrolling Interest | 563 | 31 |
| TOTAL EQUITY | 1,580,498 | 1,524,157 |
| TOTAL LIABILITIES AND EQUITY | \$5,038,902 | \$4,640,033 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Six Months Ended June 30, 2010 and 2009

(in thousands)

(Unaudited)

| | 2010 | 2009 |
|--|-----------|-----------|
| OPERATING ACTIVITIES | | |
| Net Income | \$ 57,788 | \$ 42,153 |
| Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities: | | |
| Depreciation and Amortization | 63,111 | 72,351 |
| Deferred Income Taxes | (5,742) | (29,774) |
| Extraordinary Loss, Net of Tax | - | 5,325 |
| Allowance for Equity Funds Used During Construction | (27,979) | (18,774) |
| Mark-to-Market of Risk Management Contracts | 715 | 279 |
| Property Taxes | (18,105) | (19,862) |
| Fuel Over/Under-Recovery, Net | (15,619) | 44,125 |
| Change in Other Noncurrent Assets | (11,364) | 5,731 |
| Change in Other Noncurrent Liabilities | 17,928 | 2,222 |
| Changes in Certain Components of Working Capital: | | |
| Accounts Receivable, Net | (24,733) | 88,457 |
| Fuel, Materials and Supplies | 20,096 | (4,293) |
| Accounts Payable | (10,505) | 22,698 |
| Accrued Taxes, Net | 32,339 | 64,066 |
| Other Current Assets | (825) | 1,902 |
| Other Current Liabilities | 3,704 | (54,203) |
| Net Cash Flows from Operating Activities | 80,809 | 222,403 |
| INVESTING ACTIVITIES | | |
| Construction Expenditures | (176,107) | (305,886) |
| Change in Advances to Affiliates, Net | (193,437) | (31,999) |
| Proceeds from Sales of Assets | 962 | 105,453 |
| Other Investing Activities | (2,978) | (3,911) |
| Net Cash Flows Used for Investing Activities | (371,560) | (236,343) |
| FINANCING ACTIVITIES | | |
| Capital Contribution from Parent | - | 17,500 |
| Issuance of Long-term Debt – Nonaffiliated | 399,411 | (15) |
| Borrowings from Revolving Credit Facilities | 50,339 | 58,440 |
| Change in Advances from Affiliates, Net | - | (2,526) |
| Retirement of Long-term Debt – Nonaffiliated | (53,500) | (2,203) |
| Retirement of Long-term Debt – Affiliated | (50,000) | - |
| Repayments to Revolving Credit Facilities | (48,512) | (50,740) |
| Principal Payments for Capital Lease Obligations | (5,944) | (5,266) |
| Dividends Paid on Common Stock – Nonaffiliated | (1,892) | (1,645) |
| Dividends Paid on Cumulative Preferred Stock | (114) | (114) |
| Other Financing Activities | 864 | 110 |
| Net Cash Flows from Financing Activities | 290,652 | 13,541 |

| | | |
|--|----------|----------|
| Net Decrease in Cash and Cash Equivalents | (99) | (399) |
| Cash and Cash Equivalents at Beginning of Period | 1,661 | 1,910 |
| Cash and Cash Equivalents at End of Period | \$ 1,562 | \$ 1,511 |

SUPPLEMENTARY INFORMATION

| | | |
|--|-----------|-----------|
| Cash Paid for Interest, Net of Capitalized Amounts | \$ 29,649 | \$ 50,711 |
| Net Cash Paid for Income Taxes | 19,663 | 3,816 |
| Noncash Acquisitions Under Capital Leases | 380 | 1,751 |
| Construction Expenditures Included in Accounts Payable at June 30, | 85,870 | 86,920 |

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 156.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF
REGISTRANT SUBSIDIARIES

The condensed notes to SWEPCo's condensed consolidated financial statements are combined with the condensed notes to condensed financial statements for other registrant subsidiaries. Listed below are the notes that apply to SWEPCo. The footnotes begin on page 156.

| | Footnote Reference |
|--|-----------------------|
| Significant Accounting Matters | Note 1 |
| New Accounting Pronouncements and Extraordinary Item | Note 2 |
| Rate Matters | Note 3 |
| Commitments, Guarantees and Contingencies | Note 4 |
| Acquisition | Note 5 |
| Benefit Plans | Note 6 |
| Business Segments | Note 7 |
| Derivatives and Hedging | Note 8 |
| Fair Value Measurements | Note 9 |
| Income Taxes | Note 10 |
| Financing Activities | Note 11 |
| Cost Reduction Initiatives | Note 12 |

INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANT SUBSIDIARIES

The condensed notes to condensed financial statements that follow are a combined presentation for the Registrant Subsidiaries. The following list indicates the registrants to which the footnotes apply:

| | | |
|-----|--|-------------------------------------|
| 1. | Significant Accounting Matters | APCo, CSPCo, I&M, OPCo, PSO, SWEPCo |
| 2. | New Accounting Pronouncements and Extraordinary Item | APCo, CSPCo, I&M, OPCo, PSO, SWEPCo |
| 3. | Rate Matters | APCo, CSPCo, I&M, OPCo, PSO, SWEPCo |
| 4. | Commitments, Guarantees and Contingencies | APCo, CSPCo, I&M, OPCo, PSO, SWEPCo |
| 5. | Acquisition | SWEPCo |
| 6. | Benefit Plans | APCo, CSPCo, I&M, OPCo, PSO, SWEPCo |
| 7. | Business Segments | APCo, CSPCo, I&M, OPCo, PSO, SWEPCo |
| 8. | Derivatives and Hedging | APCo, CSPCo, I&M, OPCo, PSO, SWEPCo |
| 9. | Fair Value Measurements | APCo, CSPCo, I&M, OPCo, PSO, SWEPCo |
| 10. | Income Taxes | APCo, CSPCo, I&M, OPCo, PSO, SWEPCo |
| 11. | Financing Activities | APCo, CSPCo, I&M, OPCo, PSO, SWEPCo |
| 12. | Cost Reduction Initiatives | APCo, CSPCo, I&M, OPCo, PSO, SWEPCo |

1. SIGNIFICANT ACCOUNTING MATTERS

General

The unaudited condensed financial statements and footnotes were prepared in accordance with GAAP for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the SEC. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods for each Registrant Subsidiary. Net income for the three and six months ended June 30, 2010 is not necessarily indicative of results that may be expected for the year ending December 31, 2010. The condensed financial statements are unaudited and should be read in conjunction with the audited 2009 financial statements and notes thereto, which are included in the Registrant Subsidiaries' Annual Reports on Form 10-K for the year ended December 31, 2009 as filed with the SEC on February 26, 2010.

Variable Interest Entities

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE as defined by the accounting guidance for "Variable Interest Entities." In determining whether they are the primary beneficiary of a VIE, management considers for each Registrant Subsidiary factors such as equity at risk, the amount of the VIE's variability the Registrant Subsidiary absorbs, guarantees of indebtedness, voting rights including kick-out rights, power to direct the VIE and other factors. Management believes that significant assumptions and judgments were applied consistently. In addition, the Registrant Subsidiaries have not provided financial or other support to any VIE that was not previously contractually required. Also, see the "ASU 2009-17 'Consolidations' " section of Note 2 for a discussion of the impact of new accounting guidance effective January 1, 2010.

SWEP Co is the primary beneficiary of Sabine. As of January 1, 2010, SWEP Co is no longer the primary beneficiary of DHLC as defined by new accounting guidance for "Variable Interest Entities." I&M is the primary beneficiary of DCC Fuel LLC (DCC Fuel) and DCC Fuel II LLC (DCC Fuel II). APCo, CSPCo, I&M, OPCo, PSO and SWEP Co each hold a significant variable interest in AEPSC. I&M and CSPCo each hold a significant variable interest in AEGCo. SWEP Co holds a significant variable interest in DHLC.

Sabine is a mining operator providing mining services to SWEP Co. SWEP Co has no equity investment in Sabine but is Sabine's only customer. SWEP Co guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEP Co. The creditors of Sabine have no recourse to any AEP entity other than SWEP Co. Under the provisions of the mining agreement, SWEP Co is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. In addition, SWEP Co determines how much coal will be mined for each year. Based on these facts, management concluded that SWEP Co is the primary beneficiary and is required to consolidate Sabine. SWEP Co's total billings from Sabine for the three months ended June 30, 2010 and 2009 were \$30 million and \$25 million, respectively, and for the six months ended June 30, 2010 and 2009 were \$73 million and \$61 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on SWEP Co's

Condensed Consolidated Balance Sheets.

DHLC is a mining operator who sells 50% of the lignite produced to SWEPCo and 50% to CLECO. SWEPCo and CLECO share the executive board seats and its voting rights equally. Each entity guarantees a 50% share of DHLC's debt. SWEPCo and CLECO equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC, it receives 100% of the management fee. Based on the shared control of DHLC's operations, management concluded as of January 1 2010 that SWEPCo is no longer the primary beneficiary and is no longer required to consolidate DHLC.

SWEPCo's total billings from DHLC for the three months ended June 30, 2010 and 2009 were \$13 million and \$8 million, respectively, and for the six months ended June 30, 2010 and 2009 were \$26 million and \$18 million, respectively. See the tables below for the classification of DHLC's assets and liabilities on SWEPCo's Condensed Consolidated Balance Sheet at December 31, 2009 as well as SWEPCo's investment and maximum exposure as of June 30, 2010. As of June 30, 2010, DHLC is reported as an equity investment in Deferred Charges and Other Noncurrent Assets on SWEPCo's Condensed Consolidated Balance Sheet. Also, see the "ASU 2009-17 'Consolidations'" section of Note 2 for a discussion of the impact of new accounting guidance effective January 1, 2010.

The balances below represent the assets and liabilities of the VIEs that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

**SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
VARIABLE INTEREST ENTITIES**

June 30, 2010
(in millions)

| | | Sabine |
|-----------------------------------|----|--------|
| ASSETS | | |
| Current Assets | \$ | 48 |
| Net Property, Plant and Equipment | | 144 |
| Other Noncurrent Assets | | 34 |
| Total Assets | \$ | 226 |
| LIABILITIES AND EQUITY | | |
| Current Liabilities | \$ | 31 |
| Noncurrent Liabilities | | 194 |
| Equity | | 1 |
| Total Liabilities and Equity | \$ | 226 |

**SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
VARIABLE INTEREST ENTITIES**

December 31, 2009
(in millions)

| | Sabine | DHLC |
|-----------------------------------|--------|-------|
| ASSETS | | |
| Current Assets | \$ 51 | \$ 8 |
| Net Property, Plant and Equipment | 149 | 44 |
| Other Noncurrent Assets | 35 | 11 |
| Total Assets | \$ 235 | \$ 63 |
| LIABILITIES AND EQUITY | | |
| Current Liabilities | \$ 36 | \$ 17 |
| Noncurrent Liabilities | 199 | 38 |
| Equity | - | 8 |
| Total Liabilities and Equity | \$ 235 | \$ 63 |

SWEPCo's investment in DHLC was:

| |
|------------------------------------|
| June 30, 2010 |
| As Reported on the Consolidated |
| Maximum |

| | Balance Sheet | Exposure |
|----------------------------------|---------------|----------|
| | (in millions) | |
| Capital Contribution from SWEPCo | \$ 7 | \$ 7 |
| Retained Earnings | 1 | 1 |
| SWEPCo's Guarantee of Debt | - | 48 |
| Total Investment in DHLC | \$ 8 | \$ 56 |

In September 2009, I&M entered into a nuclear fuel sale and leaseback transaction with DCC Fuel LLC. In April 2010, I&M entered into a nuclear fuel sale and leaseback transaction with DCC Fuel II LLC. DCC Fuel LLC and DCC Fuel II LLC (collectively DCC) were formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. Each entity is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. Payments on the leases are made semi-annually and began in April 2010. Payment on the leases for the three months ended June 30, 2010 and for the six months ended June 30, 2010 was \$22 million. No payments were made to DCC in 2009. The leases were recorded as capital leases on I&M's balance sheet as title to the nuclear fuel transfers to I&M at the end of the 48 and 54 month lease term, respectively. Based on I&M's control of DCC, management concluded that I&M is the primary beneficiary and is required to consolidate DCC. The capital leases are eliminated upon consolidation. See the tables below for the classification of DCC's assets and liabilities on I&M's Condensed Consolidated Balance Sheets.

The balances below represent the assets and liabilities of the VIE that are consolidated. These balances include intercompany transactions that would be eliminated upon consolidation.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
VARIABLE INTEREST ENTITIES

June 30, 2010
(in millions)

| ASSETS | DCC |
|-----------------------------------|--------|
| Current Assets | \$ 76 |
| Net Property, Plant and Equipment | 141 |
| Other Noncurrent Assets | 93 |
| Total Assets | \$ 310 |
| | |
| LIABILITIES AND EQUITY | |
| Current Liabilities | \$ 63 |
| Noncurrent Liabilities | 247 |
| Equity | - |
| Total Liabilities and Equity | \$ 310 |

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
VARIABLE INTEREST ENTITIES

December 31, 2009
(in millions)

| ASSETS | DCC |
|-----------------------------------|--------|
| Current Assets | \$ 47 |
| Net Property, Plant and Equipment | 89 |
| Other Noncurrent Assets | 57 |
| Total Assets | \$ 193 |
| | |
| LIABILITIES AND EQUITY | |
| Current Liabilities | \$ 39 |
| Noncurrent Liabilities | 154 |
| Equity | - |
| Total Liabilities and Equity | \$ 193 |

AEPSC provides certain managerial and professional services to AEP's subsidiaries. AEP is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. No AEP subsidiary has provided financial or other support outside of the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP's subsidiaries are exposed to losses to the extent they cannot recover the costs of

AEPSC through their normal business operations. All Registrant Subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, no Registrant Subsidiary has control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP.

Total AEPSC billings to the Registrant Subsidiaries were as follows:

| Company | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---------|-----------------------------|-------|---------------------------|-------|
| | 2010 | 2009 | 2010 | 2009 |
| | (in millions) | | | |
| APCo | \$ 67 | \$ 46 | \$ 126 | \$ 97 |
| CSPCo | 39 | 31 | 74 | 60 |
| I&M | 41 | 32 | 75 | 61 |
| OPCo | 63 | 46 | 112 | 87 |
| PSO | 31 | 21 | 55 | 43 |
| SWEPCo | 44 | 31 | 79 | 60 |

The carrying amount and classification of variable interest in AEPSC's accounts payable are as follows:

| Company | June 30, 2010 | | December 31, 2009 | |
|---------|----------------------------------|------------------|----------------------------------|------------------|
| | As Reported in the Balance Sheet | Maximum Exposure | As Reported in the Balance Sheet | Maximum Exposure |
| | (in millions) | | | |
| APCo | \$ 36 | \$ 36 | \$ 23 | \$ 23 |
| CSPCo | 21 | 21 | 13 | 13 |
| I&M | 21 | 21 | 13 | 13 |
| OPCo | 32 | 32 | 18 | 18 |
| PSO | 17 | 17 | 9 | 9 |
| SWEPCo | 23 | 23 | 14 | 14 |

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant Unit 1, leases a 50% interest in Rockport Plant Unit 2 and owns 100% of the Lawrenceburg Generating Station. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEGCo leases the Lawrenceburg Generating Station to CSPCo. AEP guarantees all the debt obligations of AEGCo. I&M and CSPCo are considered to have a significant interest in AEGCo due to these transactions. I&M and CSPCo are exposed to losses to the extent they cannot recover the costs of AEGCo through their normal business operations. In the event AEGCo would require financing or other support outside the billings to I&M, CSPCo and KPCo, this financing would be provided by AEP. For additional information regarding AEGCo's lease, see the "Rockport Lease" section of Note 13 in the 2009 Annual Report.

Total billings from AEGCo were as follows:

| Company | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---------|-----------------------------|-------|---------------------------|-------|
| | 2010 | 2009 | 2010 | 2009 |
| | (in millions) | | | |
| CSPCo | \$ 22 | \$ 15 | \$ 37 | \$ 32 |
| I&M | 49 | 60 | 105 | 123 |

The carrying amount and classification of variable interest in AEGCo's accounts payable are as follows:

| Company | June 30, 2010 | | December 31, 2009 | |
|---------|---|---------------------|---|---------------------|
| | As Reported in the Consolidated Balance Sheet | Maximum Exposure | As Reported in the Consolidated Balance Sheet | Maximum Exposure |
| | (in millions) | | | |
| CSPCo | \$ 10 | \$ 10 | \$ 6 | \$ 6 |
| I&M | 21 | 21 | 23 | 23 |

Related Party Transactions

SWEPCo Lignite Purchases from DHLC

Effective January 1, 2010, SWEPCo deconsolidated DHLC due to the adoption of new accounting guidance. See “ASU 2009-17 ‘Consolidations’ ” section of Note 2. DHLC sells 50% of its lignite mining output to SWEPCo and the other 50% to CLECO. SWEPCo purchased \$26 million of lignite from DHLC and recorded these costs in Fuel on its Condensed Consolidated Balance Sheet at June 30, 2010.

AEP Power Pool Purchases from OVEC

In January 2010, the AEP Power Pool began purchasing power from OVEC to serve off-system sales and retail sales through June 2010. Purchases serving off-system sales are reported net as a reduction in Electric Generation, Transmission and Distribution revenues and purchases serving retail sales are reported in Purchased Electricity for Resale expenses on the respective income statements. The following table shows the amounts recorded for the three and six months ended June 30, 2010:

| Company | Three Months Ended June 30, 2010 | | Six Months Ended June 30, 2010 | |
|----------------|-------------------------------------|-------------------------|--------------------------------|-------------------------|
| | Reported in Revenues | Reported in Expenses | Reported in Revenues | Reported in Expenses |
| (in thousands) | | | | |
| APCo | \$ 3,736 | \$ 1,441 | \$ 6,631 | \$ 3,635 |
| CSPCo | 2,113 | 815 | 3,689 | 1,963 |
| I&M | 2,131 | 822 | 3,721 | 1,980 |
| OPCo | 2,432 | 938 | 4,248 | 2,268 |

SWEPCo Revised Depreciation Rates

Effective December 2009 and May 2010, SWEPCo revised book depreciation rates for its Arkansas and Texas jurisdictions, respectively, as a result of base rate orders. In comparing 2010 and 2009, the change in depreciation rates resulted in a net decrease in depreciation expense of:

| Total Depreciation Expense Variance | |
|---|---|
| Three Months Ended June 30, 2010/2009 | Six Months Ended June 30, 2010/2009 |
| (in thousands) | |
| \$ 7,132 | \$ 10,433 |

Adjustments to Reported Cash Flows

In the Financing Activities section of SWEPCo’s Condensed Consolidated Statements of Cash Flows for the six months ended June 30, 2009, SWEPCo corrected the presentation of borrowings on lines of credit of \$58 million from Change in Short-term Debt, Net – Nonaffiliated to Borrowings from Revolving Credit Facilities. SWEPCo also corrected the presentation of repayments on lines of credit of \$51 million for the six months ended June 30, 2009 to Repayments to Revolving Credit Facilities from Change in Short-term Debt, Net – Nonaffiliated. The correction to

present borrowings and repayments on lines of credit on a gross basis was not material to SWEPCo's financial statements and had no impact on SWEPCo's previously reported net income, changes in shareholder's equity, financial position or net cash flows from financing activities.

Adjustments to Sale of Receivables Disclosure

In the “Sale of Receivables – AEP Credit” section of Note 11, the disclosure was expanded for the Registrant Subsidiaries to reflect certain prior period amounts related to the sale of receivables that were not previously disclosed. These omissions were not material to the financial statements and had no impact on the Registrant Subsidiaries’ previously reported net income, changes in shareholder’s equity, financial position or cash flows.

Adjustments to Benefit Plans Footnote

In Note 6 – Benefit Plans, the disclosure was expanded for the Registrant Subsidiaries to reflect certain prior period amounts related to the Net Periodic Benefit Cost and the Estimated Future Benefit Payments and Contributions that were not previously disclosed. These omissions were not material to the financial statements and had no impact on the Registrant Subsidiaries’ previously reported net income, changes in shareholder’s equity, financial position or cash flows.

2. NEW ACCOUNTING PRONOUNCEMENTS AND EXTRAORDINARY ITEM

NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management reviews the new accounting literature to determine its relevance, if any, to the Registrant Subsidiaries’ business. The following represents a summary of final pronouncements that impact the financial statements.

Pronouncements Adopted During 2010

The following standard was effective during the first six months of 2010. Consequently, its impact is reflected in the financial statements. The following paragraphs discuss its impact.

ASU 2009-17 “Consolidations” (ASU 2009-17)

In 2009, the FASB issued ASU 2009-17 amending the analysis an entity must perform to determine if it has a controlling financial interest in a VIE. In addition to presentation and disclosure guidance, ASU 2009-17 provides that the primary beneficiary of a VIE must have both:

- The power to direct the activities of the VIE that most significantly impact the VIE’s economic performance.
- The obligation to absorb the 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.

The Registrant Subsidiaries adopted the prospective provisions of ASU 2009-17 effective January 1, 2010. This standard required separate presentation of material consolidated VIEs’ assets and liabilities on the balance sheets. Upon adoption, SWEPCo deconsolidated DHLC. DHLC was deconsolidated due to the shared control between SWEPCo and CLECO. After January 1, 2010, SWEPCo reports DHLC using the equity method of accounting.

EXTRAORDINARY ITEM

SWEPCo Texas Restructuring

In August 2006, the PUCT adopted a rule extending the delay in implementation of customer choice in SWEPCo’s SPP area of Texas until no sooner than January 1, 2011. In May 2009, the governor of Texas signed a bill related to

SWEPCo's SPP area of Texas that requires continued cost of service regulation until certain stages have been completed and approved by the PUCT such that fair competition is available to all Texas retail customer classes. Based upon the signing of the bill, SWEPCo re-applied "Regulated Operations" accounting guidance for the generation portion of SWEPCo's Texas retail jurisdiction effective second quarter of 2009. Management believes that a switch to competition in the SPP area of Texas will not occur. The reapplication of "Regulated Operations" accounting guidance resulted in an \$8 million (\$5 million, net of tax) extraordinary loss.

3.

RATE MATTERS

As discussed in the 2009 Annual Report, the Registrant Subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within the 2009 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2010 and updates the 2009 Annual Report.

Regulatory Assets Not Yet Being Recovered

| | APCo | | I&M | |
|---|------------------|----------------------|------------------|----------------------|
| | June 30, 2010 | December 31, 2009 | June 30, 2010 | December 31, 2009 |
| Noncurrent Regulatory Assets (excluding fuel) | (in thousands) | | (in thousands) | |
| Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing: | | | | |
| Regulatory Assets Currently Not Earning a Return | | | | |
| Mountaineer Carbon Capture and Storage Project | \$ 58,085 | \$ 110,665 | \$ - | \$ - |
| Virginia Environmental Rate Adjustment Clause | 43,273 | 25,311 | - | - |
| Virginia Transmission Rate Adjustment Clause | 21,088 | 26,184 | - | - |
| Special Rate Mechanism for Century Aluminum | 12,524 | 12,422 | - | - |
| Deferred Wind Power Costs | 11,523 | 5,372 | - | - |
| Storm Related Costs | 25,437 | - | - | - |
| Deferred PJM Fees | - | - | 6,880 | 6,254 |
| Total Regulatory Assets Not Yet Being Recovered | \$ 171,930 | \$ 179,954 | \$ 6,880 | \$ 6,254 |
| | | | | |
| | CSPCo | | OPCo | |
| | June 30, 2010 | December 31, 2009 | June 30, 2010 | December 31, 2009 |
| Noncurrent Regulatory Assets (excluding fuel) | (in thousands) | | (in thousands) | |
| Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing: | | | | |
| Regulatory Assets Currently Earning a Return | | | | |
| Customer Choice Deferrals | \$ 29,197 | \$ 28,781 | \$ 28,666 | \$ 28,330 |
| | 30,121 | 26,590 | 18,741 | 16,278 |

| | | | | | |
|---|---------------|-------------------|---------------|-------------------|--|
| Line Extension Carrying Costs | | | | | |
| Storm Related Costs | 18,634 | 17,014 | 10,742 | 9,794 | |
| Acquisition of Monongahela Power | 11,108 | 10,282 | - | - | |
| Regulatory Assets Currently Not Earning a Return | | | | | |
| Peak Demand Reduction/Energy Efficiency | - (a) | 4,071 | - (a) | 4,007 | |
| Total Regulatory Assets Not Yet Being Recovered | \$ 89,060 | \$ 86,738 | \$ 58,149 | \$ 58,409 | |
| | | | | | |
| | | PSO | | SWEPCo | |
| | June 30, 2010 | December 31, 2009 | June 30, 2010 | December 31, 2009 | |
| Noncurrent Regulatory Assets (excluding fuel) | | (in thousands) | | (in thousands) | |
| Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing: | | | | | |
| Regulatory Assets Currently Not Earning a Return | | | | | |
| Storm Related Costs | \$ 15,755 | \$ - | \$ - | \$ - | |
| Asset Retirement Obligation | - | - | 558 | 471 | |
| Total Regulatory Assets Not Yet Being Recovered | \$ 15,755 | \$ - | \$ 558 | \$ 471 | |

(a) Recovery of regulatory asset was granted during 2010.

CSPCo and OPCo Rate Matters

Ohio Electric Security Plan Filings

The PUCO issued an order in March 2009 that modified and approved CSPCo's and OPCo's ESPs which established rates at the start of the April 2009 billing cycle. The ESPs are in effect through 2011. The order also limits annual rate increases for CSPCo to 7% in 2009, 6% in 2010 and 6% in 2011 and for OPCo to 8% in 2009, 7% in 2010 and 8% in 2011. Some rate components and increases are exempt from these limitations. CSPCo and OPCo collected the 2009 annualized revenue increase over the last nine months of 2009.

The order provides a FAC for the three-year period of the ESP. The FAC increase will be phased in to avoid having the resultant rate increases exceed the ordered annual caps described above. The FAC increase is subject to quarterly true-ups, annual accounting audits and prudency reviews. See the "2009 Fuel Adjustment Clause Audit" section below. The order allows CSPCo and OPCo to defer any unrecovered FAC costs resulting from the annual caps and to accrue associated carrying charges at CSPCo's and OPCo's weighted average cost of capital. Any deferred FAC regulatory asset balance at the end of the three-year ESP period will be recovered through a non-bypassable surcharge over the period 2012 through 2018. Management expects to recover the CSPCo FAC deferral during 2010. That recovery will include deferrals associated with the Ormet interim arrangement and is subject to the PUCO's ultimate decision regarding the Ormet interim arrangement deferrals plus related carrying charges. See the "Ormet Interim Arrangement" section below. The FAC deferrals as of June 30, 2010 were \$5 million and \$388 million for CSPCo and OPCo, respectively, excluding \$1 million and \$18 million, respectively, of unrecognized equity carrying costs.

Discussed below are the outstanding uncertainties related to the ESP order:

The Ohio Consumers' Counsel filed a notice of appeal with the Supreme Court of Ohio raising several issues including alleged retroactive ratemaking, recovery of carrying charges on certain environmental investments, Provider of Last Resort (POLR) charges and the decision not to offset rates by off-system sales margins. A decision from the Supreme Court of Ohio is pending.

In November 2009, the Industrial Energy Users-Ohio group filed a notice of appeal with the Supreme Court of Ohio challenging components of the ESP order including the POLR charge, the distribution riders for gridSMARTSM and enhanced reliability, the PUCO's conclusion and supporting evaluation that the modified ESPs are more favorable than the expected results of a market rate offer, the unbundling of the fuel and non-fuel generation rate components, the scope and design of the fuel adjustment clause and the approval of the plan after the 150-day statutory deadline. A decision from the Supreme Court of Ohio is pending.

In April 2010, the Industrial Energy Users-Ohio group filed an additional notice of appeal with the Supreme Court of Ohio challenging alleged retroactive ratemaking, CSPCo's and OPCo's abilities to collect through the FAC amounts deferred under the Ormet interim arrangement and the approval of the plan after the 150-day statutory deadline. A decision from the Supreme Court of Ohio is pending.

In 2009, the PUCO convened a workshop to determine the methodology for the Significantly Excessive Earnings Test (SEET). Ohio law requires that the PUCO determine, following the end of each year of the ESP, if rate adjustments included in the ESP resulted in significantly excessive earnings. If the rate adjustments, in the aggregate, result in significantly excessive earnings, the excess amount could be returned to customers. The PUCO heard arguments related to various SEET issues including the treatment of the FAC deferrals. Management believes that CSPCo and OPCo should not be required to refund unrecovered FAC regulatory assets until they are collected, even assuming there are significantly excessive earnings in that year. In June 2010, the PUCO issued an order resolving some of the SEET issues. The PUCO determined that the earnings of CSPCo and OPCo shall be calculated on an individual

company basis and not on a combined CSPCo/OPCo basis. The PUCO ruled that many issues including the treatment of deferrals and off-system sales should be determined on a case-by-case basis. The PUCO's decision on the SEET methodology is not expected to be finalized until after the SEET filings are made by CSPCo and OPCo related to 2009 earnings and the PUCO issues an order thereon. CSPCo and OPCo will file their significantly excessive earnings tests with the PUCO by their September 2010 deadlines. CSPCo and OPCo are unable to determine whether they will be required to return any of their ESP revenues to customers.

Management is unable to predict the outcome of the various ongoing ESP proceedings and litigation discussed above. If these proceedings result in adverse rulings, it could reduce future net income and cash flows and impact financial condition.

2009 Fuel Adjustment Clause Audit

As required under the ESP orders, the PUCO selected an outside consultant to conduct the audit of the FAC for the period of January 2009 through December 2009. In May 2010, the outside consultant provided their confidential audit report of the FAC audit to the PUCO. The audit report included a recommendation that the PUCO should review whether any proceeds from a 2008 coal contract settlement agreement which totaled \$72 million should reduce OPCo's FAC under-recovery balance. Of the total proceeds, approximately \$58 million was recognized as a reduction to fuel expense prior to 2009 and \$14 million will reduce fuel expense in 2009 and 2010. If the PUCO orders any portion of the \$58 million previously recognized gains be used to reduce the current year FAC deferral, it would reduce future net income and cash flows and impact financial condition.

Ormet Interim Arrangement

CSPCo, OPCo and Ormet, a large aluminum company, filed an application with the PUCO for approval of an interim arrangement governing the provision of generation service to Ormet. This interim arrangement was approved by the PUCO and was effective from January 2009 through September 2009. In March 2009, the PUCO approved a FAC in the ESP filings. The approval of the FAC, together with the PUCO approval of the interim arrangement, provided the basis to record regulatory assets for the difference between the approved market price and the rate paid by Ormet. Through September 2009, the last month of the interim arrangement, CSPCo and OPCo had \$30 million and \$34 million, respectively, of deferred FAC related to the interim arrangement including recognized carrying charges but excluding \$1 million and \$1 million, respectively, of unrecognized equity carrying costs. In November 2009, CSPCo and OPCo requested that the PUCO approve recovery of the deferrals under the interim agreement plus a weighted average cost of capital carrying charge. The interim arrangement deferrals are included in CSPCo's and OPCo's FAC phase-in deferral balances. See "Ohio Electric Security Plan Filings" section above. In the ESP proceeding, intervenors requested that CSPCo and OPCo be required to refund the Ormet-related regulatory assets and requested that the PUCO prevent CSPCo and OPCo from collecting the Ormet-related revenues in the future. The PUCO did not take any action on this request in the ESP proceeding. The intervenors raised the issue again in response to CSPCo's and OPCo's November 2009 filing to approve recovery of the deferrals under the interim agreement. If CSPCo and OPCo are not ultimately permitted to fully recover their requested deferrals under the interim arrangement, it would reduce future net income and cash flows and impact financial condition.

Economic Development Rider

In April 2010, the Industrial Energy Users-Ohio filed a notice of appeal of the 2009 PUCO-approved Economic Development Rider (EDR) with the Supreme Court of Ohio. The EDR collects from ratepayers the difference between the standard tariff and lower contract billings to qualifying industrial customers, subject to PUCO approval. The Industrial Energy Users-Ohio raised several issues including claims that (a) the PUCO lost jurisdiction over CSPCo's and OPCo's ESP proceedings and related proceedings when the PUCO failed to issue ESP orders within the 150-day statutory deadline, (b) the EDR should not be exempt from the ESP annual rate limitations and (c) CSPCo and OPCo should not be allowed to apply a weighted average long-term debt carrying cost on deferred EDR regulatory assets.

In June 2010, Industrial Energy Users-Ohio filed a notice of appeal of the 2010 PUCO-approved Economic Development Rider (EDR) with the Supreme Court of Ohio. The Industrial Energy Users-Ohio raised the same issues as noted in the 2009 EDR appeal plus a claim that CSPCo and OPCo should not be able to take the benefits of the higher ESP rates while simultaneously challenging the ESP Orders.

As of June 30, 2010, CSPCo and OPCo have incurred \$32 million and \$23 million, respectively, in EDR costs including carrying costs. Of these costs, CSPCo and OPCo have collected \$16 million and \$12 million, respectively, through the EDR, which CSPCo and OPCo began collecting in January 2010. The remaining \$16 million and \$11 million for CSPCo and OPCo, respectively, are recorded as EDR regulatory assets. If CSPCo and OPCo are not ultimately permitted to recover their deferrals or are required to refund revenue collected, it would reduce future net income and cash flows and impact financial condition.

Environmental Investment Carrying Cost Rider

In February 2010, CSPCo and OPCo filed an application with the PUCO to establish an Environmental Investment Carrying Cost Rider to recover carrying costs for 2009 through 2011 related to environmental investments made in 2009. CSPCo's and OPCo's proposed initial rider would recover 2009 carrying costs of \$29 million and \$37 million, respectively, through December 2011. In July 2010, CSPCo and OPCo filed an updated position to its application which reduced its original rider application amount to recover \$27 million and \$35 million, respectively, through December 2011. If approved, the implementation of the rider will likely not impact cash flows, but will increase the ESP phase-in plan deferrals associated with the FAC since this rider is subject to the rate increase caps authorized by the PUCO in the ESP proceedings.

Ohio IGCC Plant

In March 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs of building and operating an IGCC power plant. Through June 30, 2010, CSPCo and OPCo have each collected \$12 million in pre-construction costs authorized in a June 2006 PUCO order and each incurred \$11 million in pre-construction costs. As a result, CSPCo and OPCo each established a net regulatory liability of approximately \$1 million. The order also provided that if CSPCo and OPCo have not commenced a continuous course of construction of the proposed IGCC plant before June 2011, all pre-construction costs that may be utilized in projects at other sites must be refunded to Ohio ratepayers with interest. Intervenors have filed motions with the PUCO requesting all pre-construction costs be refunded to Ohio ratepayers with interest.

CSPCo and OPCo will not start construction of an IGCC plant until existing statutory barriers are addressed and sufficient assurance of regulatory cost recovery exists. Management cannot predict the outcome of any cost recovery litigation concerning the Ohio IGCC plant or what effect, if any, such litigation would have on future net income and cash flows. However, if CSPCo and OPCo were required to refund all or some of the pre-construction costs collected and the costs incurred were not recoverable in another jurisdiction, it would reduce future net income and cash flows and impact financial condition.

Ohio Energy Efficiency & Demand Response Program Rider

In November 2009, CSPCo and OPCo filed an application with the PUCO to implement energy efficiency and demand response programs as part of Senate Bill 221, which requires investor-owned utilities to create programs to help customers conserve and reduce demand for electricity. Simultaneous with the filing, a stipulation agreement was filed with the PUCO agreeing to terms consistent with the filed application. In May 2010, the PUCO issued an order adopting the stipulation, with minor modification, and authorized CSPCo and OPCo to implement a new rider rate effective with the first billing cycle in June 2010. The rider rates are estimated to increase CSPCo's and OPCo's revenues by \$81 million and \$86 million, respectively, over the period from June 2010 through December 2011. CSPCo's and OPCo's revenue increases include \$79 million and \$83 million, respectively, for program costs and \$2 million and \$3 million, respectively, for net lost distribution revenues and shared savings.

SWEPCo Rate Matters

Turk Plant

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which is expected to be in service in 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and will operate the completed facility. The Turk Plant is currently estimated to cost \$1.7 billion, excluding AFUDC, plus an additional \$131 million for transmission, excluding AFUDC. SWEPCo's share is currently estimated to cost \$1.3 billion, excluding AFUDC, plus an additional \$131 million for transmission, excluding AFUDC. As of June 30, 2010, excluding costs attributable to its joint owners, SWEPCo has capitalized approximately \$855 million of expenditures (including AFUDC and capitalized interest of \$106 million and related transmission costs of \$46 million). As of June 30, 2010, the joint owners and SWEPCo have contractual construction commitments of approximately \$425 million (including related transmission costs of \$7 million). SWEPCo's share of the contractual construction commitments is \$312 million. If the plant is cancelled, the joint owners and SWEPCo would incur contractual construction cancellation fees, based on construction status as of June 30, 2010, of approximately \$121 million (including related transmission cancellation fees of \$1 million). SWEPCo's share of the contractual construction cancellation fees would be approximately \$89 million.

Discussed below are the outstanding uncertainties related to the Turk Plant:

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the 88 MW SWEPCo Arkansas share of the Turk Plant. Following an appeal by certain intervenors, the Arkansas Supreme Court issued a decision that reversed the APSC's grant of the CECPN. The Arkansas Supreme Court ultimately concluded that the APSC erred in determining the need for additional power supply resources in a proceeding separate from the proceeding in which the APSC granted the CECPN. However, the Arkansas Supreme Court approved the APSC's procedure of granting CECPNs for transmission facilities in dockets separate from the Turk Plant CECPN proceeding. In June 2010, the Arkansas Supreme Court denied motions for rehearing filed by the APSC and SWEPCo. Therefore, SWEPCo filed a notice with the APSC of its intent to proceed with construction of the Turk Plant but that SWEPCo no longer intends to pursue a CECPN to seek recovery of the originally approved 88MW portion of Turk Plant costs in Arkansas retail rates. In June 2010, the APSC issued an order which reversed and set aside the previously granted CECPN.

In July 2010, the Hempstead County Hunting Club filed a complaint with the Federal District Court for the Western District of Arkansas against SWEPCo, the U.S. Army Corps of Engineers, the U.S. Department of Interior and the U.S. Fish and Wildlife Service seeking an injunction to stop construction of the Turk Plant asserting claims of violations of federal and state laws.

The PUCT issued an order approving a Certificate of Convenience and Necessity (CCN) for the Turk Plant with the following conditions: (a) a cap on the recovery of jurisdictional capital costs for the Turk Plant based on the previously estimated \$1.522 billion projected construction cost, excluding AFUDC and related transmission costs, (b) a cap on recovery of annual CO₂ emission costs at \$28 per ton through the year 2030 and (c) a requirement to hold Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers. SWEPCo appealed the PUCT's order contending the two cost cap restrictions are unlawful. The Texas Industrial Energy Consumers filed an appeal contending that the PUCT's grant of a conditional CCN for the Turk Plant was unnecessary to serve retail customers. In February 2010, the Texas District Court affirmed the PUCT's order in all respects. In March 2010, SWEPCo and the Texas Industrial Energy Consumers appealed this decision to the Texas Court of Appeals.

The LPSC approved SWEPCo's application to construct the Turk Plant. The Sierra Club petitioned the LPSC to begin an investigation into the construction of the Turk Plant which was rejected by the LPSC in November 2009. In

December 2009, the Sierra Club refiled its petition as a stand alone complaint proceeding. In February 2010, SWEPCo filed a motion to dismiss and denied the allegations in the complaint.

In November 2008, SWEPCo received its required air permit approval from the Arkansas Department of Environmental Quality and commenced construction at the site. The Arkansas Pollution Control and Ecology Commission (APCEC) upheld the air permit. In February 2010, the parties who unsuccessfully appealed the air permit to the APCEC filed a notice of appeal with the Circuit Court of Hempstead County, Arkansas.

The wetlands permit was issued by the U.S. Army Corps of Engineers in December 2009. In February 2010, the Sierra Club, the Audubon Society and others filed a complaint in the Federal District Court for the Western District of Arkansas against the U.S. Army Corps of Engineers challenging the process used and the terms of the permit issued to SWEPCo authorizing certain wetland and stream impacts. In May 2010, parties filed with the Federal District Court for the Western District of Arkansas for a preliminary injunction to halt construction and for a temporary restraining order.

In January 2009, SWEPCo was granted CECPNs by the APSC to build three transmission lines and facilities authorized by the SPP and needed to transmit power from the Turk Plant. Intervenor appealed the CECPN decisions in April 2009 to the Arkansas Court of Appeals. In July 2010, the Hempstead County Hunting Club and other appellants filed with the Arkansas Court of Appeals emergency motions to stay the transmission CECPNs to prohibit SWEPCo from taking ownership of private property and undertaking construction of the transmission lines. In July 2010, the Arkansas Court of Appeals issued a decision remanding all transmission line CECPN appeals to the APSC. As a result, a stay was not ordered and construction continues on the affected transmission lines.

Management expects that SWEPCo will ultimately be able to complete construction of the Turk Plant and related transmission facilities and place those facilities in service. However, if SWEPCo is unable to complete the Turk Plant construction, including the related transmission facilities, and place the Turk Plant in service or if SWEPCo cannot recover all of its investment in and expenses related to the Turk Plant, it would materially reduce future net income and cash flows and materially impact financial condition.

Stall Unit

SWEPCo constructed the Stall Unit, an intermediate load 500 MW natural gas-fired combustion turbine combined cycle generating unit, at its existing Arsenal Hill Plant located in Shreveport, Louisiana. The LPSC and the APSC issued orders capping SWEPCo's Stall Unit construction costs at \$445 million including AFUDC and excluding related transmission costs. The Stall Unit was placed in service in June 2010. As of June 30, 2010, the Stall Unit cost \$422 million, including \$49 million of AFUDC. Management does not expect the final costs of the Stall Unit to exceed the ordered cap.

Louisiana Fuel Adjustment Clause Audit

Consultants for the LPSC issued their audit report of SWEPCo's Louisiana retail FAC. The audit report included a significant recommendation that might result in a financial impact that could be material for SWEPCo. The audit report recommended that the LPSC discontinue SWEPCo's tiered sharing mechanism related to off-system sales margins on a prospective basis. In addition, the audit report contained a recommendation that SWEPCo should reflect the SIA refunds as reductions in the Louisiana FAC rates as soon as possible, including interest through the date the refunds are reflected in the FAC. See "Allocation of Off-system Sales Margins" section within "FERC Rate Matters." Management is unable to predict how the LPSC will rule on the recommendations in the audit report and its financial statement impact on net income, cash flows and financial condition.

2009 Texas Base Rate Filing

In August 2009, SWEPCo filed a rate case with the PUCT to increase its base rates by approximately \$75 million annually including a return on equity of 11.5%. The filing included requests for financing cost riders of \$32 million

related to construction of the Stall Unit and Turk Plant, a vegetation management rider of \$16 million and other requested increases of \$27 million. In April 2010, a settlement agreement was approved by the PUCT to increase SWEPCo's base rates by approximately \$15 million annually, effective May 2010, including a return on equity of 10.33%, which consists of \$5 million related to construction of the Stall Unit and \$10 million in other increases. In addition, the settlement agreement will decrease annual depreciation expense by \$17 million and allows SWEPCo a \$10 million one-year surcharge rider to recover additional vegetation management costs that SWEPCo must spend within two years.

Texas Fuel Reconciliation

In May 2010, various intervenors, including the PUCT staff, filed testimony recommending disallowances ranging from \$3 million to \$30 million in SWEPCo's \$755 million fuel and purchase power costs reconciliation for the period January 2006 through March 2009. In July 2010, Cities Advocating Reasonable Deregulation filed testimony regarding the 2007 transfer of ERCOT trading contracts to AEP Energy Partners. Included in this testimony were unquantified refund recommendations relating to re-pricing of contract transactions. Management is unable to predict the outcome of this reconciliation. If the PUCT disallows any portion of SWEPCo's fuel and purchase power costs, it could reduce future net income and cash flows and possibly impact financial condition.

Louisiana 2008 Formula Rate Filing

In April 2008, SWEPCo filed its first formula rate filing under an approved three-year formula rate plan (FRP). SWEPCo requested an increase in its annual Louisiana retail rates of \$11 million to be effective in August 2008 in order to earn the approved formula return on common equity of 10.565%. In August 2008, as provided by the FRP, SWEPCo implemented the FRP rates, subject to refund. During 2009, SWEPCo recorded a provision for refund of approximately \$1 million after reaching a settlement in principle with intervenors. A settlement stipulation was reached by the parties and is pending LPSC approval.

Louisiana 2009 Formula Rate Filing

In April 2009, SWEPCo filed the second FRP which would increase its annual Louisiana retail rates by an additional \$4 million effective in August 2009. SWEPCo implemented the FRP rate increase as filed in August 2009, subject to refund. In October 2009, consultants for the LPSC objected to certain components of SWEPCo's FRP calculation. The consultants also recommended reflecting the SIA refunds through SWEPCo's FRP. See "Allocation of Off-system Sales Margins" section within "FERC Rate Matters." SWEPCo is currently in settlement discussions. If a refund is required, it could reduce future net income and cash flows and impact financial condition.

Louisiana 2010 Formula Rate Filing

In April 2010, SWEPCo filed the third FRP which would decrease its annual Louisiana retail rates by \$3 million effective in August 2010 pursuant to the approved FRP, subject to refund. SWEPCo believes the rates as filed are in compliance with the FRP methodology previously approved by the LPSC. If the LPSC disagrees with SWEPCo, it could result in refunds which could reduce future net income and cash flows and impact financial condition.

APCo Rate Matters

2009 Virginia Base Rate Case

In July 2009, APCo filed a generation and distribution base rate increase with the Virginia SCC of \$154 million annually based on a 13.35% return on common equity. Interim rates, subject to refund, became effective in December 2009 but were discontinued in February 2010 when newly enacted Virginia legislation suspended the collection of interim rates. In July 2010, the Virginia SCC issued an order approving a \$62 million increase based on a 10.53% return on equity. The order denied recovery of the Virginia share of the Mountaineer Carbon Capture and Storage Project, which resulted in a pretax write-off of \$54 million in the second quarter of 2010. See "Mountaineer Carbon Capture and Storage Project" section below. In addition, the order allowed the deferral in the second quarter of 2010 of approximately \$25 million of incremental storm expense incurred in 2009. In July 2010, APCo filed with the Virginia SCC a petition for reconsideration of the order as it relates to the Mountaineer Carbon Capture and Storage Project.

2010 West Virginia Base Rate Case

In May 2010, APCo filed a request with the WVPSC to increase annual base rates by \$140 million based on an 11.75% return on common equity to be effective March 2011. Hearings are scheduled for December 2010. A decision from the WVPSC is expected in March 2011.

Mountaineer Carbon Capture and Storage Project

APCo and ALSTOM Power, Inc., an unrelated third party, jointly constructed a CO₂ capture validation facility, which was placed into service in September 2009. APCo also constructed and owns the necessary facilities to store the CO₂. In October 2009, APCo started injecting CO₂ into the underground storage facilities. The injection of CO₂ required the recording of an asset retirement obligation and an offsetting regulatory asset. Through June 30, 2010, APCo has recorded a noncurrent regulatory asset of \$58 million consisting of \$38 million in project costs and \$20 million in asset retirement costs.

In APCo's July 2009 Virginia base rate filing, APCo requested recovery of and a return on its estimated increased Virginia jurisdictional share of its project costs and recovery of the related asset retirement obligation regulatory asset amortization and accretion. In July 2010, the Virginia SCC issued a base rate order that denied recovery of the Virginia share of the Mountaineer Carbon Capture and Storage Project costs, which resulted in a write-off of approximately \$54 million in the second quarter of 2010. In response to the order, APCo filed with the Virginia SCC a petition for reconsideration of the order as it relates to the Mountaineer Carbon Capture and Storage Project. See "2009 Virginia Base Rate Case" section above.

In APCo's May 2010 West Virginia base rate filing, APCo requested recovery of and a return on its estimated increased West Virginia jurisdictional share of its project costs and recovery of the related asset retirement obligation regulatory asset amortization and accretion. If APCo cannot recover its remaining investment in and expenses related to the Mountaineer Carbon Capture and Storage project, it would reduce future net income and cash flows and impact financial condition.

APCo's Filings for an IGCC Plant

APCo filed a petition with the WVPSC requesting approval of a Certificate of Public Convenience and Necessity (CPCN) to construct a 629 MW IGCC power plant in Mason County, West Virginia. APCo also requested the Virginia SCC and the WVPSC to approve a surcharge rate mechanism to provide for the timely recovery of pre-construction costs and the ongoing financing costs of the project during the construction period, as well as the capital costs, operating costs and a return on equity once the facility is placed into commercial operation. The WVPSC granted APCo the CPCN and approved the requested cost recovery. Various intervenors filed petitions with the WVPSC to reconsider the order.

In 2008, the Virginia SCC issued an order denying APCo's request for a surcharge rate mechanism based upon its finding that the estimated cost of the plant was uncertain and may escalate. The Virginia SCC also expressed concerns that the estimated costs did not include a retrofitting of carbon capture and sequestration facilities. During 2009, based on an unfavorable order received in Virginia, the WVPSC removed the IGCC case as an active case from its docket and indicated that the conditional CPCN granted in 2008 must be reconsidered if and when APCo proceeds forward with the IGCC plant.

Through June 30, 2010, APCo deferred for future recovery pre-construction IGCC costs of approximately \$9 million applicable to its West Virginia jurisdiction, approximately \$2 million applicable to its FERC jurisdiction and approximately \$9 million applicable to its Virginia jurisdiction.

APCo will not start construction of the IGCC plant until sufficient assurance of full cost recovery exists in Virginia and in West Virginia. If the plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs which, if not recoverable, would reduce future net income and cash flows and impact financial condition.

APCo's 2009 Expanded Net Energy Charge (ENEC) Filing

In September 2009, the WVPSC issued an order approving APCo's March 2009 ENEC request. The approved order provided for recovery of an under-recovered balance plus a projected increase in ENEC costs over a four-year phase-in period with an overall increase of \$320 million and a first-year increase of \$112 million, effective October 2009. The WVPSC also approved a fixed annual carrying cost rate of 4%, effective October 2009, to be applied to the incremental deferred regulatory asset balance that will result from the phase-in plan and lowered annual coal cost projections by \$27 million. As of June 30, 2010, APCo's ENEC under-recovery balance was \$358 million, including carrying costs, which is included in noncurrent regulatory assets.

In June 2010, a settlement agreement for \$86 million, including \$9 million of construction surcharges, was filed with the WVPSC related to APCo's second year ENEC increase. The settlement agreement provided for recovery of the amounts related to the renegotiated coal contracts and allows APCo to accrue weighted average cost of capital carrying costs on the excess under-recovery balance due to the ENEC phase-in as adjusted for the impacts of Accumulated Deferred Income Taxes. In June 2010, the WVPSC approved the settlement agreement which made rates effective in July 2010.

WPCo Merger with APCo

In a proceeding established by the WVPSC to explore options to meet WPCo's future power supply requirements, the WVPSC, in November 2009, issued an order approving a joint stipulation among APCo, WPCo, the WVPSC staff and the Consumer Advocate Division. The order approved the recommendation of the signatories to the stipulation that WPCo merge into APCo and be supplied from APCo's existing power resources. Merger approvals from the WVPSC, Virginia SCC and the FERC are required. No merger approval filings have been made.

PSO Rate Matters

PSO Fuel and Purchased Power

2006 and Prior Fuel and Purchased Power

The OCC filed a complaint with the FERC related to the allocation of off-system sales margins (OSS) among the AEP operating companies in accordance with a FERC-approved allocation agreement. The FERC issued an adverse ruling in 2008. As a result, PSO recorded a regulatory liability in 2008 to return reallocated OSS to customers. Starting in March 2009, PSO refunded the additional reallocated OSS to its customers through February 2010.

A reallocation of purchased power costs among AEP West companies for periods prior to 2002 resulted in an under-recovery of \$42 million of PSO fuel costs. PSO recovered the \$42 million by offsetting it against an existing fuel over-recovery during the period June 2007 through May 2008. The Oklahoma Industrial Energy Consumers (OIEC) has contended that PSO should not have collected the \$42 million without specific OCC approval. As such, the OIEC contends that the OCC should require PSO to refund the \$42 million it collected through its fuel clause. The OCC has heard the OIEC appeal and a decision is pending. In March 2010, PSO filed motions to advance this proceeding since the FERC has ruled on the allocation of off-system sales margins proceeding and PSO has refunded the additional margins to its retail customers. If the OCC were to order PSO to refund all or a part of the \$42 million, it would reduce future net income and cash flows and impact financial condition.

2008 Fuel and Purchased Power

In July 2009, the OCC initiated a proceeding to review PSO's fuel and purchased power adjustment clause for the calendar year 2008 and also initiated a prudence review of the related costs. In March 2010, the Oklahoma Attorney General and the OIEC recommended the fuel clause adjustment rider be amended so that the shareholder's portion of off-system sales margins decrease from 25% to 10%. The OIEC also recommended that the OCC conduct a comprehensive review of all affiliate transactions during 2007 and 2008. In July 2010, additional testimony regarding the 2007 transfer of ERCOT trading contracts to AEP Energy Partners was filed. Included in this testimony were unquantified refund recommendations relating to re-pricing of contract transactions. If the OCC were to issue an unfavorable decision, it could reduce future net income and cash flows and impact financial condition.

2008 Oklahoma Base Rate Appeal

In January 2009, the OCC issued a final order approving an \$81 million increase in PSO's non-fuel base revenues based on a 10.5% return on equity. The new rates reflecting the final order were implemented with the first billing cycle of February 2009. PSO and intervenors filed appeals with the Oklahoma Supreme Court raising various issues. The Oklahoma Supreme Court assigned the case to the Court of Civil Appeals. In June 2010, the Court of Civil Appeals affirmed the OCC's decision. No parties sought rehearing or appeal. As a result, this case has concluded.

2010 Oklahoma Base Rate Case

In July 2010, PSO filed a request with the OCC to increase annual base rates by \$82 million, including \$30 million that is currently being recovered through a rider. The requested increase includes a \$24 million increase in depreciation and an 11.5% return on common equity. PSO requested that new rates become effective no later than July 2011. A procedural schedule has not been established.

I&M Rate Matters

Indiana Fuel Clause Filing (Cook Plant Unit 1 Fire and Shutdown)

I&M filed applications with the IURC to increase its fuel adjustment charge by approximately \$53 million for the period of April 2009 through September 2009. The filings sought increases for previously under-recovered fuel clause expenses.

As fully discussed in the “Cook Plant Unit 1 Fire and Shutdown” section of Note 4, Cook Unit 1 was shut down in September 2008 due to significant turbine damage and a small fire on the electric generator. Unit 1 was placed back into service in December 2009 at slightly reduced power. The unit outage resulted in increased replacement power fuel costs. The filing only requested the cost of replacement power through mid-December 2008, the date when I&M began receiving accidental outage insurance proceeds. I&M committed to absorb the remaining costs of replacement power through the date the unit returned to service, which occurred in December 2009.

I&M reached an agreement with intervenors, which was approved by the IURC in March 2009, to collect its existing prior period under-recovery regulatory asset deferral balance over twelve months instead of over six months as initially proposed. Under the agreement, the fuel factors were placed into effect, subject to refund, and a subdocket was established to consider issues relating to the Unit 1 shutdown including the treatment of the accidental outage insurance proceeds. Hearings are scheduled to be held in December 2010.

Management believes that I&M is entitled to retain the accidental outage insurance proceeds since it made customers whole regarding the replacement power costs. If any fuel clause revenues or accidental outage insurance proceeds have to be refunded, it would reduce future net income and cash flows and impact financial condition.

Michigan 2009 Power Supply Cost Recovery (PSCR) Reconciliation (Cook Plant Unit 1 Fire and Shutdown)

In March 2010, I&M filed its 2009 PSCR reconciliation with the MPSC. The filing included an adjustment to exclude from the PSCR the incremental fuel cost of replacement power due to the Cook Plant Unit 1 outage from mid-December 2008 through December 2009, the period during which I&M received and recognized the accidental outage insurance proceeds. Management believes that I&M is entitled to retain the accidental outage insurance proceeds since it made customers whole regarding the replacement power costs. If any fuel clause revenues or accidental outage insurance proceeds have to be refunded, it would reduce future net income and cash flows and impact financial condition. See the “Cook Plant Unit 1 Fire and Shutdown” section of Note 4.

Michigan Base Rate Filing

In January 2010, I&M filed with the MPSC a request for a \$63 million increase in annual base rates based on an 11.75% return on common equity. In the August 2010 billing cycle, I&M, with the MPSC authorization, will implement a \$44 million interim rate increase, subject to refund with interest. The interim increase excluded new trackers and regulatory assets for which I&M was not currently incurring expenses. In July 2010, the MPSC staff filed testimony which recommended a \$34 million annual increase in base rates based on a 10.35% return on common equity plus separate recovery of approximately \$7 million of customer choice implementation costs over a two year

period. The MPSC must issue a final order within one year of the original filing.

FERC Rate Matters

Regional Transmission Rate Proceedings at the FERC – Affecting APCo, CSPCo, I&M and OPCo

Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund

In 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected, at the FERC's direction, load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 2006. Intervenors objected to the temporary SECA rates. The FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies recognized gross SECA revenues of \$220 million from 2004 through 2006 when the SECA rates terminated leaving the AEP East companies and ultimately their internal load retail customers to make up the shortfall in revenues. APCo's, CSPCo's, I&M's and OPCo's portions of recognized gross SECA revenues are as follows:

| Company | (in millions) |
|---------|---------------|
| APCo | \$ 70.2 |
| CSPCo | 38.8 |
| I&M | 41.3 |
| OPCo | 53.3 |

In 2006, a FERC Administrative Law Judge (ALJ) issued an initial decision finding that the rate design for the recovery of SECA charges was flawed and that a large portion of the "lost revenues" reflected in the SECA rates should not have been recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made. The ALJ also found that any unpaid SECA rates must be paid in the recommended reduced amount.

AEP filed briefs jointly with other affected companies noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision. In May 2010, the FERC issued an order that generally supports AEP's position and requires a compliance filing to be filed with the FERC by August 2010. In June 2010, AEP and other affected companies filed a joint request for rehearing with the FERC regarding certain matters including a request to clarify the method for determining the amount of such revenues. The rehearing also requested the FERC to clarify that interest may be added to SECA charges originally billed to but never paid by Green Mountain Energy (reassigned to British Petroleum Energy). Eight other groups also filed requests for rehearing with the FERC.

The AEP East companies provided reserves for net refunds for SECA settlements totaling \$44 million applicable to the \$220 million of SECA revenues collected. APCo's, CSPCo's, I&M's and OPCo's portions of the provision are as follows:

| Company | (in millions) |
|---------|---------------|
| APCo | \$ 14.1 |
| CSPCo | 7.8 |
| I&M | 8.3 |
| OPCo | 10.7 |

Settlements approved by the FERC consumed \$10 million of the reserve for refunds applicable to \$112 million of SECA revenue. The balance in the reserve for future settlements as of June 30, 2010 was \$34 million. APCo's, CSPCo's, I&M's and OPCo's reserve balances at June 30, 2010 were:

| Company | June 30, 2010 |
|---------|---------------|
|---------|---------------|

| | (in millions) |
|-------|---------------|
| APCo | \$ 10.7 |
| CSPCo | 5.9 |
| I&M | 6.3 |
| OPCo | 8.2 |

Based on the AEP East companies' analysis of the May 2010 order, management believes that the reserve is adequate to pay the refunds, including interest, that will be required should the May 2010 order be made final as issued by the FERC. Management cannot predict the ultimate outcome of this proceeding at the FERC which could impact future net income and cash flows.

Allocation of Off-system Sales Margins – Affecting SWEPCo

The OCC filed a complaint at the FERC alleging that AEP inappropriately allocated off-system sales margins between the AEP East companies and the AEP West companies and did not properly allocate off-system sales margins within the AEP West companies.

In 2009, AEP made a compliance filing with the FERC and the AEP East companies refunded approximately \$250 million to the AEP West companies. Following authorized regulatory treatment, the AEP West companies shared a portion of SIA margins with their customers during the period June 2000 to March 2006. In 2008, the AEP West companies recorded a provision for refund reflecting the sharing. Refunds have been or are currently being returned to PSO's and SWEPCo's Texas, Arkansas and FERC customers. SWEPCo is working with the LPSC to determine how the FERC ordered refund will be made to its Louisiana retail customers. Consultants for the LPSC issued an audit report of SWEPCo's Louisiana retail fuel adjustment clause, in which they recommended that SWEPCo refund the amounts, including interest, through the fuel adjustment clause. See "Louisiana Fuel Adjustment Clause Audit" section within "SWEPCo Rate Matters." Other consultants for the LPSC recommended refunding the amounts through SWEPCo's formula rate plan. Management believes the AEP West companies' provision for refund is adequate.

Modification of the Transmission Agreement (TA) – Affecting APCo, CSPCo, I&M and OPCo

APCo, CSPCo, I&M, KPCo and OPCo are parties to the TA that provides for a sharing of the cost of transmission lines operated at 138-kV and above and transmission stations containing extra-high voltage facilities. In June 2009, AEPSC, on behalf of the parties to the TA, filed with the FERC a request to modify the TA. Under the proposed amendments, KGPCo and WPCo will be added as parties to the TA. In addition, the amendments would provide for the allocation of PJM transmission costs on the basis of the TA parties' 12-month coincident peak and reimburse transmission revenues based on individual cost of service instead of the MLR method used in the present TA. AEPSC requested the effective date to be the first day of the month following a final non-appealable FERC order. The delayed effective date was approved by the FERC when the FERC accepted the new TA for filing. Settlement discussions are in progress. Management is unable to predict whether the parties to the TA will experience regulatory lag and its effect on future net income and cash flows due to timing of the implementation of the modified TA by various state regulators.

PJM Transmission Formula Rate Filing – Affecting APCo, CSPCo, I&M and OPCo

AEP filed an application with the FERC in July 2008 to increase its open access transmission tariff (OATT) rates for wholesale transmission service within PJM. The filing sought to implement a formula rate allowing annual adjustments reflecting future changes in the AEP East companies' cost of service. The FERC issued an order conditionally accepting AEP's proposed formula rate and delayed the requested October 2008 effective date for five months. AEP began settlement discussions with the intervenors and the FERC staff which resulted in a settlement that was filed with the FERC in April 2010.

The pending settlement results in a \$51 million annual increase beginning in April 2009 for service as of March 2009, of which approximately \$7 million is being collected from nonaffiliated customers within PJM. The remaining \$44 million is being billed to the AEP East companies and is generally offset by compensation from PJM for use of the AEP East companies' transmission facilities so that net income is not directly affected.

The pending settlement also results in an additional \$30 million increase for the first annual update of the formula rate, beginning in August 2009 for service as of July 2009. Approximately \$4 million of the increase will be collected from nonaffiliated customers within PJM with the remaining \$26 million being billed to the AEP East companies.

Under the formula, an annual update will be filed to be effective July 2010 and each year thereafter. Also, beginning with the July 2010 update, the rates each year will include an adjustment to true-up the prior year's collections to the actual costs for the prior year. In May 2010, the second annual update was filed with the FERC to decrease the revenue requirement by \$58 million for service as of July 2010. Approximately \$8 million of the decrease will be refunded to nonaffiliated customers within PJM. Management expects the settlement will be approved by the FERC.

Transmission Agreement (TA) – Affecting APCo, CSPCo, I&M and OPCo

Certain transmission facilities placed in service in 1998 were inadvertently excluded from the AEP East companies' TA calculation prior to January 2009. The excluded equipment was KPCo's Inez Station which had been determined as eligible equipment for inclusion in the TA in 1995 by the AEP TA transmission committee. The amount involved was \$7 million annually. In June 2010, the KPSC approved a settlement agreement in KPCo's base rate filing which set new base rates effective July 2010 and excluded consideration of this issue.

PJM/MISO Market Flow Calculation Settlement Adjustments - Affecting APCo, CSPCo, I&M and OPCo

During 2009, an analysis conducted by MISO and PJM discovered several instances of unaccounted for power flows on numerous coordinated flowgates. These flows affected the settlement data for congestion revenues and expenses and date back to the start of the MISO market in 2005. PJM has provided MISO an initial analysis of amounts they believe they owe MISO. MISO disputes PJM's methodology.

Settlement discussions between MISO and PJM have been unsuccessful, and as a result, in March 2010, MISO filed two related complaints against PJM at the FERC related to the above claim. MISO seeks to recover a total of approximately \$145 million from PJM. If PJM is held liable for these damages, PJM members, including the AEP East companies, may be billed for a share of the refunds or payments PJM is directed to make to MISO. AEP has intervened and filed a protest to one complaint. Management believes that MISO's claims are without merit and that PJM's right to recover any MISO damages from AEP and other members is limited. If the FERC orders a settlement above the AEP East companies' reserve related to their estimated portion of PJM additional costs, it could reduce future net income and cash flows and impact financial condition.

4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

The Registrant Subsidiaries are subject to certain claims and legal actions arising in their ordinary course of business. In addition, their business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on the financial statements. The Commitments, Guarantees and Contingencies note within the 2009 Annual Report should be read in conjunction with this report.

GUARANTEES

Liabilities for guarantees are recorded in accordance with the accounting guidance for "Guarantees." There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

Letters of Credit – Affecting APCo, I&M, OPCo and SWEPCo

Certain Registrant Subsidiaries enter into standby letters of credit with third parties. These letters of credit cover items such as insurance programs, security deposits and debt service reserves. These letters of credit were issued in the ordinary course of business under the two \$1.5 billion credit facilities, of which \$750 million may be issued under

one credit facility as letters of credit. In June 2010, AEP canceled a facility that was scheduled to mature in March 2011 and entered into a new \$1.5 billion credit facility scheduled to mature in 2013 that allows for the issuance of up to \$600 million as letters of credit.

In June 2010, the Registrant Subsidiaries and certain other companies in the AEP System reduced the \$627 million credit agreement to \$478 million. As of June 30, 2010, \$477 million of letters of credit were issued by Registrant Subsidiaries under the agreement to support variable rate Pollution Control Bonds.

At June 30, 2010, the maximum future payments of the letters of credit were as follows:

| Company | Amount (in thousands) | Maturity | Borrower Sublimit (in thousands) |
|----------------------------------|--------------------------|---------------|--|
| \$1.5 billion letters of credit: | | | |
| I&M | \$ 300 | March 2011 | N/A |
| SWEPCo | 4,448 | December 2010 | N/A |
| \$478 million letter of credit: | | | |
| November 2010 to April | | | |
| APCo | \$ 232,292 | 2011 | \$ 300,000 |
| I&M | 77,886 | April 2011 | 230,000 |
| OPCo | 166,899 | April 2011 | 400,000 |

Guarantees of Third-Party Obligations – Affecting SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of approximately \$65 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine Mining Company (Sabine), a consolidated variable interest entity. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study, it is estimated the reserves will be depleted in 2036 with final reclamation completed by 2046 at an estimated cost of approximately \$58 million. As of June 30, 2010, SWEPCo has collected approximately \$46 million through a rider for final mine closure and reclamation costs, of which \$2 million is recorded in Other Current Liabilities, \$22 million is recorded in Deferred Credits and Other Noncurrent Liabilities and \$22 million is recorded in Asset Retirement Obligations on SWEPCo's Condensed Consolidated Balance Sheets.

Sabine charges SWEPCo, its only customer, all of its costs. SWEPCo passes these costs to customers through its fuel clause.

Indemnifications and Other Guarantees – Affecting APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

Contracts

The Registrant Subsidiaries enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. Prior to June 30, 2010, the Registrant Subsidiaries entered into sale agreements including indemnifications with a maximum exposure that was not significant for any individual Registrant Subsidiary. There are no material liabilities recorded for any indemnifications.

The AEP East companies, PSO and SWEPCo are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to power purchase and sale activity conducted pursuant to the SIA.

Master Lease Agreements

The Registrant Subsidiaries lease certain equipment under master lease agreements. GE Capital Commercial Inc. (GE) notified management in November 2008 that they elected to terminate the Master Leasing Agreements in accordance with the termination rights specified within the contract. In 2011, the Registrant Subsidiaries will be required to purchase all equipment under the lease and pay GE an amount equal to the unamortized value of all equipment then leased. In December 2008 and 2009, management signed new master lease agreements that include lease terms of up to 10 years.

For equipment under the GE master lease agreements that expire in 2011, the lessor is guaranteed receipt of up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair value of the leased equipment is below the unamortized balance at the end of the lease term, the Registrant Subsidiaries are committed to pay the difference between the fair value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. Under the new master lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, the Registrant Subsidiaries are committed to pay the difference between the actual fair value and the residual value guarantee. At June 30, 2010, the maximum potential loss by Registrant Subsidiary for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term is as follows:

| Company | Maximum Potential Loss (in thousands) |
|---------|--|
| APCo | \$ 236 |
| CSPCo | 57 |
| I&M | 153 |
| OPCo | 306 |
| PSO | 329 |
| SWEPCo | 272 |

Historically, at the end of the lease term the fair value has been in excess of the unamortized balance.

Railcar Lease

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years via the renewal options. The future minimum lease obligations are \$18 million for I&M and \$20 million for SWEPCo for the remaining railcars as of June 30, 2010.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines from approximately 84% under the current five year lease term to 77% at the end of the 20 year term of the projected fair value of the equipment. I&M and SWEPCo have assumed the guarantee under the return-and-sale option. I&M's maximum potential loss related to the guarantee is approximately \$12 million (\$8 million, net of tax) and SWEPCo's is approximately \$13 million (\$9 million, net of tax) assuming the fair value of the equipment is zero at the end of the current five-year lease term. However,

management believes that the fair value would produce a sufficient sales price to avoid any loss.

The Registrant Subsidiaries have other railcar lease arrangements that do not utilize this type of financing structure.

ENVIRONMENTAL CONTINGENCIES

Federal EPA Complaint and Notice of Violation – Affecting CSPCo

The Federal EPA, certain special interest groups and a number of states alleged that APCo, CSPCo, I&M and OPCo modified certain units at their coal-fired generating plants in violation of the NSR requirements of the CAA. Cases with similar allegations against CSPCo, Dayton Power and Light Company and Duke Energy Ohio, Inc. were also filed related to their jointly-owned units. The cases were settled with the exception of a case involving a jointly-owned Beckjord unit which had a liability trial. Following the trial, the jury found no liability for claims made against the jointly-owned Beckjord unit. Following a second liability trial in 2009, the jury again found no liability at the jointly-owned Beckjord unit. The defendants and the plaintiffs appealed to the Seventh Circuit Court of Appeals. Beckjord is operated by Duke Energy Ohio, Inc. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Notice of Enforcement and Notice of Citizen Suit – Affecting SWEPCo

In 2005, two special interest groups, Sierra Club and Public Citizen, filed a complaint alleging violations of the CAA at SWEPCo's Welsh Plant. In 2008, a consent decree resolved all claims in the case and in the pending appeal of an altered permit for the Welsh Plant. The consent decree required SWEPCo to install continuous particulate emission monitors at the Welsh Plant, secure 65 MW of renewable energy capacity, fund \$2 million in emission reduction, energy efficiency or environmental mitigation projects and pay a portion of plaintiffs' attorneys' fees and costs.

The Federal EPA issued a Notice of Violation (NOV) based on alleged violations of a percent sulfur in fuel limitation and the heat input values listed in a previous state permit. The NOV also alleges that a permit alteration issued by the Texas Commission on Environmental Quality in 2007 was improper. In March 2008, SWEPCo met with the Federal EPA to discuss the alleged violations. The Federal EPA did not object to the settlement of similar alleged violations in the federal citizen suit. Management is unable to predict the timing of any future action by the Federal EPA. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Carbon Dioxide Public Nuisance Claims – Affecting APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

In 2004, eight states and the City of New York filed an action in Federal District Court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The trial court dismissed the lawsuits.

In September 2009, the Second Circuit Court of Appeals issued a ruling on appeal remanding the cases to the Federal District Court for the Southern District of New York. The Second Circuit held that the issues of climate change and global warming do not raise political questions and that Congress' refusal to regulate CO2 emissions does not mean that plaintiffs must wait for an initial policy determination by Congress or the President's administration to secure the relief sought in their complaints. The court stated that Congress could enact comprehensive legislation to regulate CO2 emissions or that the Federal EPA could regulate CO2 emissions under existing CAA authorities and that either of these actions could override any decision made by the district court under federal common law. The Second Circuit did not rule on whether the plaintiffs could proceed with their state common law nuisance claims. The defendants' petition for rehearing was denied. Management believes the actions are without merit and intends to continue to defend against the claims. The Solicitor General requested an extension of time to file a petition for review by the U.S. Supreme Court and the remaining defendants received a similar extension of time. Petitions are currently due on or before August 2, 2010.

In October 2009, the Fifth Circuit Court of Appeals reversed a decision by the Federal District Court for the District of Mississippi dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that CO₂ emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs' complaint to a coordinate branch of government and that no initial policy determination was required to adjudicate these claims. The court granted petitions for rehearing. An additional recusal left the Fifth Circuit without a quorum to reconsider the decision and the appeal was dismissed, leaving the district court's decision in place. The Registrant Subsidiaries were initially dismissed from this case without prejudice, but are named as defendants in a pending fourth amended complaint. Unless the plaintiffs elect to file a petition for review by the U.S. Supreme Court, there will be no further proceedings in this case.

Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Alaskan Villages' Claims – Affecting APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil and gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of CO₂ contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of \$95 million to \$400 million. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. The plaintiffs appealed the decision. Management believes the action is without merit and intends to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation – Affecting I&M

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, the generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and nonhazardous materials. The Registrant Subsidiaries currently incur costs to dispose of these substances safely.

In March 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. In May 2008, I&M started remediation work in accordance with a plan approved by MDEQ. I&M recorded approximately \$11 million of expense prior to January 1, 2010, \$3 million of which I&M recorded in March 2009. As the remediation work is completed, I&M's cost may continue to increase as new information becomes available concerning either the level of contamination at the site or changes in the scope of remediation required by the MDEQ. Management cannot predict the amount of additional cost, if any.

Amos Plant – Request to Show Cause – Affecting APCo and OPCo

In March 2010, APCo and OPCo received a request to show cause from the Federal EPA alleging that certain reporting requirements under Superfund and the Emergency Planning and Community Right-to-Know Act had been violated and inviting APCo and OPCo to engage in settlement negotiations. The request includes a proposed civil penalty of approximately \$300 thousand. Management indicated a willingness to engage in good faith negotiations

and met with representatives of the Federal EPA. APCo and OPCo have not admitted that any violations occurred or that the amount of the proposed penalty is reasonable. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Defective Environmental Equipment – Affecting CSPCo and OPCo

As part of the AEP System's continuing environmental investment program, management chose to retrofit wet flue gas desulfurization systems on units utilizing the jet bubbling reactor (JBR) technology. The following plants have been scheduled for the installation of the JBR technology or are currently utilizing JBR retrofits:

| Plant Name | Plant Owners | JBRs Scheduled for Installation |
|-----------------|---------------------------------------|---------------------------------------|
| Cardinal | OPCo/Buckeye Power, Inc. | 3 |
| | CSPCo/Dayton Power and Light Company/ | |
| Conesville | Duke Energy Ohio, Inc. | 1 |
| Muskingum River | | |
| (a) | OPCo | 1 |

- (a) Contracts for the Muskingum River project have been temporarily suspended during the early development stage of the project.

The retrofits on two of the Cardinal Plant units and the Conesville Plant unit are operational. Due to unexpected operating results, management completed an extensive review of the design and manufacture of the JBR internal components. The review concluded that there are fundamental design deficiencies and that inferior and/or inappropriate materials were selected for the internal fiberglass components. Management initiated discussions with Black & Veatch, the original equipment manufacturer, to develop a repair or replacement corrective action plan. Management intends to pursue contractual and other legal remedies if these issues with Black & Veatch are not resolved. If the AEP System is unsuccessful in obtaining reimbursement for the work required to remedy this situation, the cost of repair or replacement could have an adverse impact on construction costs, net income, cash flows and financial condition. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

NUCLEAR CONTINGENCIES – AFFECTING I&M

I&M owns and operates the two-unit 2,191 MW Cook Plant under licenses granted by the Nuclear Regulatory Commission. I&M has a significant future financial commitment to dispose of SNF and to safely decommission and decontaminate the plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. The operation of a nuclear facility also involves special risks, potential liabilities and specific regulatory and safety requirements. By agreement, I&M is partially liable, together with all other electric utility companies that own nuclear generating units, for a nuclear power plant incident at any nuclear plant in the U.S. Should a nuclear incident occur at any nuclear power plant in the U.S., the resultant liability could be substantial.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in significant turbine damage and a small fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and are within the vendor's warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately \$395 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process. I&M repaired Unit 1 and it resumed operations in December 2009 at slightly reduced

power. The Unit 1 rotors were repaired and reinstalled due to the extensive lead time required to manufacture and install new turbine rotors. As a result, the replacement of the repaired turbine rotors and other equipment is scheduled for the Unit 1 planned outage in the fall of 2011.

I&M maintains property insurance through NEIL with a \$1 million deductible. As of June 30, 2010, I&M recorded \$53 million on its Condensed Consolidated Balance Sheet representing recoverable amounts under the property insurance policy. Through June 30, 2010, I&M received partial payments of \$203 million from NEIL for the cost incurred to date to repair the property damage.

I&M also maintains a separate accidental outage policy with NEIL. In 2009, I&M recorded \$185 million in revenue under the policy and reduced the cost of replacement power in customers' bills by \$78 million.

NEIL is reviewing claims made under the insurance policies to ensure that claims associated with the outage are covered by the policies. The treatment of property damage costs, replacement power costs and insurance proceeds will be the subject of future regulatory proceedings in Indiana and Michigan. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if any future regulatory proceedings are adverse, it could have an adverse impact on net income, cash flows and financial condition.

OPERATIONAL CONTINGENCIES

Fort Wayne Lease – Affecting I&M

Since 1975 I&M has leased certain energy delivery assets from the City of Fort Wayne, Indiana under a long-term lease that expires on February 28, 2010. I&M has been negotiating with Fort Wayne to purchase the assets at the end of the lease, but no agreement has been reached. Fort Wayne issued a technical notice of default under the lease to I&M in August 2009. I&M responded to Fort Wayne in October 2009 that it did not agree there was a default under the lease. In October 2009, I&M filed for declaratory and injunctive relief in Indiana state court. The parties agreed to submit this matter to mediation. In February 2010, the court issued a stay to continue mediation. I&M is making monthly payments to an escrow account in lieu of rent. I&M will seek recovery in rates for any amount it may pay related to this dispute. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Coal Transportation Rate Dispute - Affecting PSO

In 1985, the Burlington Northern Railroad Co. (now BNSF) entered into a coal transportation agreement with PSO. The agreement contained a base rate subject to adjustment, a rate floor, a reopener provision and an arbitration provision. In 1992, PSO reopened the pricing provision. The parties failed to reach an agreement and the matter was arbitrated, with the arbitration panel establishing a lowered rate as of July 1, 1992 (the 1992 Rate) and modifying the rate adjustment formula. The decision did not mention the rate floor. From April 1996 through the contract termination in December 2001, the 1992 Rate exceeded the adjusted rate determined according to the decision. PSO paid the adjusted rate and contended that the panel eliminated the rate floor. BNSF invoiced at the 1992 Rate and contended that the 1992 Rate was the new rate floor. PSO terminated the contract by paying a termination fee, as required by the agreement. BNSF contends that the termination fee should have been calculated on the 1992 Rate, not the adjusted rate, resulting in an underpayment of approximately \$9.5 million, including interest.

This matter was submitted to an arbitration board. In April 2006, the arbitration board filed its decision, denying BNSF's underpayments claim. PSO filed a request for an order confirming the arbitration award and a request for entry of judgment on the award with the U.S. District Court for the Northern District of Oklahoma. On July 14, 2006, the U.S. District Court issued an order confirming the arbitration award. On July 24, 2006, BNSF filed a Motion to Reconsider the July 14, 2006 Arbitration Confirmation Order and Final Judgment and its Motion to Vacate and Correct the Arbitration Award with the U.S. District Court. In February 2007, the U.S. District Court granted BNSF's Motion to Reconsider. In August 2009, the U.S. District Court upheld the arbitration board's decision. BNSF appealed the U.S. District Court's decision.

5. ACQUISITION

2010

Valley Electric Membership Corporation – Affecting SWEPCo

In November 2009, SWEPCo signed a letter of intent to purchase the transmission and distribution assets of Valley Electric Membership Corporation (VEMCO). The current estimate of the purchase is approximately \$100 million, plus the assumption of certain liabilities, subject to adjustments at closing. Consummation of the transaction is subject to regulatory approval by the LPSC, the APSC, the Rural Utilities Service, the National Rural Utilities Cooperative Finance Corporation and the FERC. In January 2010, the VEMCO members approved the transaction. In the second quarter of 2010, a purchase and sales agreement was signed and a joint application between SWEPCo and VEMCO was filed with the LPSC. SWEPCo will seek recovery from Louisiana customers for all costs related to this acquisition. VEMCO services approximately 30,000 customers in Louisiana. SWEPCo expects to complete the transaction in the third quarter of 2010 upon receipt of regulatory approvals.

2009

None

6. BENEFIT PLANS

APCo, CSPCo, I&M, OPCo, PSO and SWEPCo participate in AEP sponsored qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. In addition, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo participate in other postretirement benefit plans sponsored by AEP to provide medical and death benefits for retired employees.

Components of Net Periodic Benefit Cost

The following tables provide the components of the Registrant Subsidiaries' net periodic benefit cost for the plans for the three and six months ended June 30, 2010 and 2009:

APCo

| | Pension Plans | | Other Postretirement Benefit Plans | |
|---------------------------------------|-----------------------------|-----------|------------------------------------|----------|
| | Three Months Ended June 30, | | Three Months Ended June 30, | |
| | 2010 | 2009 | 2010 | 2009 |
| | (in thousands) | | | |
| Service Cost | \$3,227 | \$3,172 | \$1,430 | \$1,286 |
| Interest Cost | 8,489 | 8,513 | 5,075 | 4,927 |
| Expected Return on Plan Assets | (10,951) | (11,221) | (4,407) | (3,383) |
| Amortization of Transition Obligation | - | - | 1,311 | 1,311 |
| Amortization of Prior Service Cost | 229 | 229 | - | - |
| Amortization of Net Actuarial Loss | 2,961 | 1,922 | 1,353 | 1,916 |
| Net Periodic Benefit Cost | \$3,955 | \$2,615 | \$4,762 | \$6,057 |

| | Pension Plans | | Other Postretirement Benefit Plans | |
|--|---------------------------|------|------------------------------------|------|
| | Six Months Ended June 30, | | Six Months Ended June 30, | |
| | 2010 | 2009 | 2010 | 2009 |

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| | (in thousands) | | | |
|---------------------------------------|----------------|-----------|----------|----------|
| Service Cost | \$6,454 | \$6,345 | \$2,860 | \$2,572 |
| Interest Cost | 16,978 | 17,025 | 10,150 | 9,855 |
| Expected Return on Plan Assets | (21,902) | (22,442) | (8,813) | (6,766) |
| Amortization of Transition Obligation | - | - | 2,622 | 2,622 |
| Amortization of Prior Service Cost | 458 | 458 | - | - |
| Amortization of Net Actuarial Loss | 5,921 | 3,844 | 2,705 | 3,832 |
| Net Periodic Benefit Cost | \$7,909 | \$5,230 | \$9,524 | \$12,115 |

CSPCo

| | Pension Plans | | Other Postretirement Benefit Plans | |
|---------------------------------------|-----------------------------|----------|------------------------------------|----------|
| | Three Months Ended June 30, | | Three Months Ended June 30, | |
| | 2010 | 2009 | 2010 | 2009 |
| | (in thousands) | | | |
| Service Cost | \$1,468 | \$1,376 | \$690 | \$618 |
| Interest Cost | 4,789 | 4,882 | 2,179 | 2,123 |
| Expected Return on Plan Assets | (6,589) | (6,819) | (1,979) | (1,531) |
| Amortization of Transition Obligation | - | - | 608 | 608 |
| Amortization of Prior Service Cost | 141 | 141 | - | - |
| Amortization of Net Actuarial Loss | 1,677 | 1,108 | 565 | 821 |
| Net Periodic Benefit Cost | \$1,486 | \$688 | \$2,063 | \$2,639 |

| | Pension Plans | | Other Postretirement Benefit Plans | |
|---------------------------------------|---------------------------|-----------|------------------------------------|----------|
| | Six Months Ended June 30, | | Six Months Ended June 30, | |
| | 2010 | 2009 | 2010 | 2009 |
| | (in thousands) | | | |
| Service Cost | \$2,936 | \$2,752 | \$1,380 | \$1,235 |
| Interest Cost | 9,578 | 9,765 | 4,357 | 4,246 |
| Expected Return on Plan Assets | (13,178) | (13,638) | (3,958) | (3,063) |
| Amortization of Transition Obligation | - | - | 1,216 | 1,216 |
| Amortization of Prior Service Cost | 282 | 282 | - | - |
| Amortization of Net Actuarial Loss | 3,354 | 2,215 | 1,130 | 1,643 |
| Net Periodic Benefit Cost | \$2,972 | \$1,376 | \$4,125 | \$5,277 |

I&M

| | Pension Plans | | Other Postretirement Benefit Plans | |
|---------------------------------------|-----------------------------|----------|------------------------------------|----------|
| | Three Months Ended June 30, | | Three Months Ended June 30, | |
| | 2010 | 2009 | 2010 | 2009 |
| | (in thousands) | | | |
| Service Cost | \$3,821 | \$3,501 | \$1,688 | \$1,497 |
| Interest Cost | 7,271 | 7,130 | 3,541 | 3,419 |
| Expected Return on Plan Assets | (8,760) | (8,933) | (3,349) | (2,565) |
| Amortization of Transition Obligation | - | - | 704 | 704 |
| Amortization of Prior Service Cost | 186 | 186 | - | - |
| Amortization of Net Actuarial Loss | 2,516 | 1,601 | 881 | 1,303 |
| Net Periodic Benefit Cost | \$5,034 | \$3,485 | \$3,465 | \$4,358 |

| | Pension Plans | | Other Postretirement Benefit Plans | |
|--------------------------------|---------------------------|-----------|------------------------------------|----------|
| | Six Months Ended June 30, | | Six Months Ended June 30, | |
| | 2010 | 2009 | 2010 | 2009 |
| | (in thousands) | | | |
| Service Cost | \$7,642 | \$7,001 | \$3,375 | \$2,995 |
| Interest Cost | 14,543 | 14,260 | 7,082 | 6,837 |
| Expected Return on Plan Assets | (17,520) | (17,866) | (6,698) | (5,129) |

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| | | | | |
|---------------------------------------|-----------|----------|----------|----------|
| Amortization of Transition Obligation | - | - | 1,407 | 1,407 |
| Amortization of Prior Service Cost | 372 | 372 | - | - |
| Amortization of Net Actuarial Loss | 5,032 | 3,203 | 1,763 | 2,606 |
| Net Periodic Benefit Cost | \$ 10,069 | \$ 6,970 | \$ 6,929 | \$ 8,716 |

OPCo

| | Pension Plans | | Other Postretirement Benefit Plans | |
|---------------------------------------|-----------------------------|-----------|------------------------------------|----------|
| | Three Months Ended June 30, | | Three Months Ended June 30, | |
| | 2010 | 2009 | 2010 | 2009 |
| | (in thousands) | | | |
| Service Cost | \$2,845 | \$2,759 | \$1,357 | \$1,219 |
| Interest Cost | 8,186 | 8,275 | 4,446 | 4,331 |
| Expected Return on Plan Assets | (10,680) | (11,069) | (4,044) | (3,139) |
| Amortization of Transition Obligation | - | - | 1,053 | 1,053 |
| Amortization of Prior Service Cost | 227 | 227 | - | - |
| Amortization of Net Actuarial Loss | 2,861 | 1,875 | 1,154 | 1,676 |
| Net Periodic Benefit Cost | \$3,439 | \$2,067 | \$3,966 | \$5,140 |

| | Pension Plans | | Other Postretirement Benefit Plans | |
|---------------------------------------|---------------------------|-----------|------------------------------------|----------|
| | Six Months Ended June 30, | | Six Months Ended June 30, | |
| | 2010 | 2009 | 2010 | 2009 |
| | (in thousands) | | | |
| Service Cost | \$5,691 | \$5,517 | \$2,713 | \$2,439 |
| Interest Cost | 16,372 | 16,550 | 8,893 | 8,663 |
| Expected Return on Plan Assets | (21,360) | (22,138) | (8,089) | (6,280) |
| Amortization of Transition Obligation | - | - | 2,106 | 2,105 |
| Amortization of Prior Service Cost | 454 | 455 | - | - |
| Amortization of Net Actuarial Loss | 5,721 | 3,750 | 2,308 | 3,352 |
| Net Periodic Benefit Cost | \$6,878 | \$4,134 | \$7,931 | \$10,279 |

PSO

| | Pension Plans | | Other Postretirement Benefit Plans | |
|---------------------------------------|-----------------------------|----------|------------------------------------|----------|
| | Three Months Ended June 30, | | Three Months Ended June 30, | |
| | 2010 | 2009 | 2010 | 2009 |
| | (in thousands) | | | |
| Service Cost | \$1,513 | \$1,436 | \$704 | \$631 |
| Interest Cost | 3,722 | 3,842 | 1,590 | 1,539 |
| Expected Return on Plan Assets | (4,935) | (5,110) | (1,528) | (1,174) |
| Amortization of Transition Obligation | - | - | 701 | 701 |
| Amortization of Prior Service Credit | (238) | (270) | - | - |
| Amortization of Net Actuarial Loss | 1,297 | 872 | 393 | 587 |
| Net Periodic Benefit Cost | \$1,359 | \$770 | \$1,860 | \$2,284 |

| | Pension Plans | | Other Postretirement Benefit Plans | |
|--------------------------------|---------------------------|-----------|------------------------------------|----------|
| | Six Months Ended June 30, | | Six Months Ended June 30, | |
| | 2010 | 2009 | 2010 | 2009 |
| | (in thousands) | | | |
| Service Cost | \$3,026 | \$2,872 | \$1,407 | \$1,261 |
| Interest Cost | 7,444 | 7,684 | 3,180 | 3,077 |
| Expected Return on Plan Assets | (9,870) | (10,219) | (3,055) | (2,348) |

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| | | | | |
|---------------------------------------|---------|---------|---------|---------|
| Amortization of Transition Obligation | - | - | 1,403 | 1,403 |
| Amortization of Prior Service Credit | (475) | (541) | - | - |
| Amortization of Net Actuarial Loss | 2,594 | 1,744 | 786 | 1,174 |
| Net Periodic Benefit Cost | \$2,719 | \$1,540 | \$3,721 | \$4,567 |

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SWEPCo

| | Pension Plans | | Other Postretirement Benefit Plans | |
|---------------------------------------|-----------------------------|----------|------------------------------------|----------|
| | Three Months Ended June 30, | | Three Months Ended June 30, | |
| | 2010 | 2009 | 2010 | 2009 |
| | (in thousands) | | | |
| Service Cost | \$1,761 | \$1,689 | \$777 | \$705 |
| Interest Cost | 3,773 | 3,889 | 1,735 | 1,684 |
| Expected Return on Plan Assets | (4,872) | (5,021) | (1,661) | (1,280) |
| Amortization of Transition Obligation | - | - | 615 | 615 |
| Amortization of Prior Service Credit | (199) | (229) | - | - |
| Amortization of Net Actuarial Loss | 1,311 | 879 | 428 | 640 |
| Net Periodic Benefit Cost | \$1,774 | \$1,207 | \$1,894 | \$2,364 |

| | Pension Plans | | Other Postretirement Benefit Plans | |
|---------------------------------------|---------------------------|-----------|------------------------------------|----------|
| | Six Months Ended June 30, | | Six Months Ended June 30, | |
| | 2010 | 2009 | 2010 | 2009 |
| | (in thousands) | | | |
| Service Cost | \$3,523 | \$3,378 | \$1,554 | \$1,409 |
| Interest Cost | 7,547 | 7,779 | 3,470 | 3,368 |
| Expected Return on Plan Assets | (9,745) | (10,042) | (3,323) | (2,560) |
| Amortization of Transition Obligation | - | - | 1,230 | 1,230 |
| Amortization of Prior Service Credit | (398) | (458) | - | - |
| Amortization of Net Actuarial Loss | 2,621 | 1,758 | 856 | 1,280 |
| Net Periodic Benefit Cost | \$3,548 | \$2,415 | \$3,787 | \$4,727 |

The following table provides the Registrant Subsidiaries' actual contributions and payments for the pension and OPEB plans during the first half of 2010 and the expected contributions and payments for the remainder of 2010:

| Company | Paid as of June 30, 2010 | | Remainder Expected to be Paid in 2010 | |
|---------|------------------------------------|---------------|---------------------------------------|---------------|
| | Other Postretirement Benefit Plans | | Other Postretirement Benefit Plans | |
| | Pension Plans | Benefit Plans | Pension Plans | Benefit Plans |
| | (in thousands) | | | |
| APCo | \$ 9,682 | \$ 10,888 | \$ 9,254 | \$ 6,133 |
| CSPCo | 3,274 | 4,690 | 3,129 | 3,574 |
| I&M | 9,947 | 8,100 | 9,507 | 7,098 |
| OPCo | 8,966 | 9,560 | 8,571 | 6,136 |
| PSO | 3,478 | 4,272 | 3,325 | 4,026 |
| SWEPCo | 4,799 | 4,374 | 4,587 | 4,097 |

7.

BUSINESS SEGMENTS

The Registrant Subsidiaries each have one reportable segment, an integrated electricity generation, transmission and distribution business. The Registrant Subsidiaries' other activities are insignificant. The Registrant Subsidiaries' operations are managed on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight on the business process, cost structures and operating results.

8.

DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

The Registrant Subsidiaries are exposed to certain market risks as major power producers and marketers of wholesale electricity, coal and emission allowances. These risks include commodity price risk, interest rate risk, credit risk and to a lesser extent foreign currency exchange risk. These risks represent the risk of loss that may impact the Registrant Subsidiaries due to changes in the underlying market prices or rates. These risks are managed using derivative instruments.

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STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

The strategy surrounding the use of derivative instruments focuses on managing risk exposures, future cash flows and creating value based on open trading positions by utilizing both economic and formal hedging strategies. To accomplish these objectives, AEPSC, on behalf of the Registrant Subsidiaries, primarily employs risk management contracts including physical forward purchase and sale contracts, financial forward purchase and sale contracts and financial swap instruments. Not all risk management contracts meet the definition of a derivative under the accounting guidance for “Derivatives and Hedging.” Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

AEPSC, on behalf of the Registrant Subsidiaries, enters into electricity, coal, natural gas, interest rate and to a lesser degree heating oil, gasoline, emission allowance and other commodity contracts to manage the risk associated with the energy business. AEPSC, on behalf of the Registrant Subsidiaries, enters into interest rate derivative contracts in order to manage the interest rate exposure associated with long-term commodity derivative positions. For disclosure purposes, such risks are grouped as “Commodity,” as these risks are related to energy risk management activities. From time to time, AEPSC, on behalf of the Registrant Subsidiaries, also engages in risk management of interest rate risk associated with debt financing and foreign currency risk associated with future purchase obligations denominated in foreign currencies. For disclosure purposes, these risks are grouped as “Interest Rate and Foreign Currency.” The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with established risk management policies as approved by the Finance Committee of AEP’s Board of Directors.

The following tables represent the gross notional volume of the Registrant Subsidiaries’ outstanding derivative contracts as of June 30, 2010 and December 31, 2009:

Notional Volume of Derivative Instruments
June 30, 2010
(in thousands)

| Primary Risk Exposure | Unit of Measure | APCo | CSPCo | I&M | OPCo | PSO | SWEPCo |
|------------------------------------|-----------------|-----------|----------|----------|----------|--------|----------|
| Commodity: | | | | | | | |
| Power | MWHs | 293,757 | 166,188 | 168,869 | 191,251 | 39 | 72 |
| Coal | Tons | 12,408 | 6,854 | 6,443 | 29,978 | 4,581 | 7,357 |
| Natural Gas | MMBtus | 9,595 | 5,428 | 5,474 | 6,247 | 153 | 181 |
| Heating Oil and Gasoline | Gallons | 1,289 | 563 | 634 | 952 | 757 | 696 |
| Interest Rate | USD | \$ 12,710 | \$ 7,185 | \$ 7,230 | \$ 9,038 | \$ 745 | \$ 957 |
| Interest Rate and Foreign Currency | USD | \$ - | \$ - | \$ - | \$ - | \$ - | \$ 2,386 |

Notional Volume of Derivative Instruments
December 31, 2009
(in thousands)

| Primary Risk Exposure | Unit of Measure | APCo | CSPCo | I&M | OPCo | PSO | SWEPCo |
|-----------------------|-----------------|------|-------|-----|------|-----|--------|
|-----------------------|-----------------|------|-------|-----|------|-----|--------|

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| | | | | | | | |
|-------------------|---------|-----------|-----------|-----------|-----------|----------|----------|
| Commodity: | | | | | | | |
| Power | MWHs | 191,121 | 96,828 | 99,265 | 112,745 | 10 | 12 |
| Coal | Tons | 11,347 | 5,615 | 5,150 | 23,631 | 5,936 | 6,790 |
| Natural Gas | MMBtus | 17,867 | 9,051 | 9,129 | 10,539 | - | - |
| Heating Oil and | | | | | | | |
| Gasoline | Gallons | 1,164 | 474 | 552 | 838 | 668 | 628 |
| Interest Rate | USD | \$ 21,054 | \$ 10,658 | \$ 10,716 | \$ 13,487 | \$ 1,137 | \$ 1,457 |
| Interest Rate and | | | | | | | |
| Foreign | | | | | | | |
| Currency | USD | \$ - | \$ - | \$ - | \$ - | \$ - | \$ 3,798 |

Fair Value Hedging Strategies

AEPSC, on behalf of the Registrant Subsidiaries, enters into interest rate derivative transactions as part of an overall strategy to manage the mix of fixed-rate and floating-rate debt. Certain interest rate derivative transactions effectively modify an exposure to interest rate risk by converting a portion of fixed-rate debt to a floating rate. Provided specific criteria are met, these interest rate derivatives are designated as fair value hedges.

Cash Flow Hedging Strategies

AEPSC, on behalf of the Registrant Subsidiaries, enters into and designates as cash flow hedges certain derivative transactions for the purchase and sale of electricity, coal, heating oil and natural gas (“Commodity”) in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. Management closely monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and fuel or energy purchases. The Registrant Subsidiaries do not hedge all commodity price risk.

The Registrant Subsidiaries’ vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of the Registrant Subsidiaries, enters into financial gasoline and heating oil derivative contracts in order to mitigate price risk of future fuel purchases. For disclosure purposes, these contracts are included with other hedging activity as “Commodity.” The Registrant Subsidiaries do not hedge all fuel price risk.

AEPSC, on behalf of the Registrant Subsidiaries, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify exposure to interest rate risk by converting a portion of floating-rate debt to a fixed rate. AEPSC, on behalf of the Registrant Subsidiaries, also enters into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. The anticipated fixed-rate debt offerings have a high probability of occurrence as the proceeds will be used to fund existing debt maturities and projected capital expenditures. The Registrant Subsidiaries do not hedge all interest rate exposure.

At times, the Registrant Subsidiaries are exposed to foreign currency exchange rate risks primarily because some fixed assets are purchased from foreign suppliers. In accordance with AEP’s risk management policy, AEPSC, on behalf of the Registrant Subsidiaries, may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency’s appreciation against the dollar. The Registrant Subsidiaries do not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON THE FINANCIAL STATEMENTS

The accounting guidance for “Derivatives and Hedging” requires recognition of all qualifying derivative instruments as either assets or liabilities on the balance sheet at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, the Registrant Subsidiaries also apply valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract’s term and at the time

a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with management's estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions, margin requirements and the timing of settlement of risk management contracts.

According to the accounting guidance for “Derivatives and Hedging,” the Registrant Subsidiaries reflect the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, the Registrant Subsidiaries are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the June 30, 2010 and December 31, 2009 balance sheets, the Registrant Subsidiaries netted cash collateral received from third parties against short-term and long-term risk management assets and cash collateral paid to third parties against short-term and long-term risk management liabilities as follows:

| Company | June 30, 2010 | | December 31, 2009 | |
|---------|--|---|--|---|
| | Cash Collateral Received Netted Against Risk Management Assets | Cash Collateral Paid Netted Against Risk Management Liabilities | Cash Collateral Received Netted Against Risk Management Assets | Cash Collateral Paid Netted Against Risk Management Liabilities |
| | (in thousands) | | | |
| APCo | \$ 6,359 | \$ 28,476 | \$ 3,789 | \$ 31,806 |
| CSPCo | 3,598 | 16,097 | 1,920 | 16,108 |
| I&M | 3,628 | 16,230 | 1,936 | 16,222 |
| OPCo | 4,140 | 18,903 | 2,235 | 19,512 |
| PSO | 1 | 120 | - | 194 |
| SWEPCo | 1 | 159 | - | 305 |

The following tables represent the gross fair value of the Registrant Subsidiaries' derivative activity on the Condensed Balance Sheets as of June 30, 2010 and December 31, 2009:

Fair Value of Derivative Instruments
June 30, 2010

APCo

| Balance Sheet Location | Risk Management Contracts | Hedging Contracts | | | Total |
|--|---------------------------------|-------------------|---|---------------|-----------|
| | Commodity | Commodity | Interest Rate and Foreign Currency (a) | Other (a) (b) | |
| | (a) | (a) | (a) | | |
| | | | (in thousands) | | |
| Current Risk Management Assets | \$ 303,711 | \$ 2,573 | \$ - | \$ (251,465) | \$ 54,819 |
| Long-term Risk Management Assets | 141,135 | 218 | - | (93,265) | 48,088 |
| Total Assets | 444,846 | 2,791 | - | (344,730) | 102,907 |
| Current Risk Management Liabilities | 285,003 | 4,547 | - | (264,711) | 24,839 |
| Long-term Risk Management Liabilities | 126,190 | 429 | - | (106,875) | 19,744 |
| Total Liabilities | 411,193 | 4,976 | - | (371,586) | 44,583 |
| Total MTM Derivative Contract Net Assets (Liabilities) | \$ 33,653 | \$ (2,185) | \$ - | \$ 26,856 | \$ 58,324 |

Fair Value of Derivative Instruments
December 31, 2009

APCo

| Balance Sheet Location | Risk Management Contracts | Hedging Contracts | | | Total |
|--------------------------------|---------------------------------|-------------------|---|---------------|-----------|
| | Commodity | Commodity | Interest Rate and Foreign Currency (a) | Other (a) (b) | |
| | (a) | (a) | (a) | | |
| | | | (in thousands) | | |
| Current Risk Management Assets | \$ 332,764 | \$ 3,621 | \$ - | \$ (268,429) | \$ 67,956 |
| | 132,044 | - | - | (84,903) | 47,141 |

Long-term Risk

Management Assets

| | | | | | |
|--------------|---------|-------|---|------------|---------|
| Total Assets | 464,808 | 3,621 | - | (353,332) | 115,097 |
|--------------|---------|-------|---|------------|---------|

Current Risk Management

| | | | | | |
|-------------|---------|-------|---|------------|--------|
| Liabilities | 309,639 | 5,084 | - | (288,931) | 25,792 |
|-------------|---------|-------|---|------------|--------|

Long-term Risk

| | | | | | |
|------------------------|---------|----|---|-----------|--------|
| Management Liabilities | 118,702 | 80 | - | (98,418) | 20,364 |
|------------------------|---------|----|---|-----------|--------|

| | | | | | |
|-------------------|---------|-------|---|------------|--------|
| Total Liabilities | 428,341 | 5,164 | - | (387,349) | 46,156 |
|-------------------|---------|-------|---|------------|--------|

Total MTM Derivative

Contract Net

| | | | | | |
|----------------------|-----------|-------------|------|-----------|-----------|
| Assets (Liabilities) | \$ 36,467 | \$ (1,543) | \$ - | \$ 34,017 | \$ 68,941 |
|----------------------|-----------|-------------|------|-----------|-----------|

Fair Value of Derivative Instruments
June 30, 2010

CSPCo

| Balance Sheet Location | Risk Management Contracts | Hedging Contracts | | | Total |
|---------------------------------------|---------------------------|-------------------|------------------------------------|---------------|-----------|
| | Commodity | Commodity | Interest Rate and Foreign Currency | Other (a) (b) | |
| | | | (a) | | |
| | | | | | |
| (in thousands) | | | | | |
| Current Risk Management Assets | \$ 171,457 | \$ 1,444 | \$ - | \$ (141,939) | \$ 30,962 |
| Long-term Risk Management Assets | 79,750 | 123 | - | (52,669) | 27,204 |
| Total Assets | 251,207 | 1,567 | - | (194,608) | 58,166 |
| Current Risk Management Liabilities | 160,892 | 2,558 | - | (149,429) | 14,021 |
| Long-term Risk Management Liabilities | 71,291 | 234 | - | (60,360) | 11,165 |
| Total Liabilities | 232,183 | 2,792 | - | (209,789) | 25,186 |
| Total MTM Derivative Contract Net | | | | | |
| Assets (Liabilities) | \$ 19,024 | \$ (1,225) | \$ - | \$ 15,181 | \$ 32,980 |

Fair Value of Derivative Instruments
December 31, 2009

CSPCo

| Balance Sheet Location | Risk Management Contracts | | Hedging Contracts | | Other (a) (b) | Total |
|----------------------------------|---------------------------|-----------|------------------------------------|---------------|---------------|-------|
| | Commodity | Commodity | Interest Rate and Foreign Currency | (a) | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| (in thousands) | | | | | | |
| Current Risk Management Assets | \$ 168,137 | \$ 1,805 | \$ - | \$ (135,599) | \$ 34,343 | |
| Long-term Risk Management Assets | 66,816 | - | - | (42,934) | 23,882 | |
| Total Assets | 234,953 | 1,805 | - | (178,533) | 58,225 | |

| | | | | | |
|-------------------------|-----------|-----------|------|------------|-----------|
| Current Risk Management | | | | | |
| Liabilities | 156,463 | 2,574 | - | (145,985) | 13,052 |
| Long-term Risk | | | | | |
| Management Liabilities | 60,048 | 41 | - | (49,776) | 10,313 |
| Total Liabilities | 216,511 | 2,615 | - | (195,761) | 23,365 |
| Total MTM Derivative | | | | | |
| Contract Net | | | | | |
| Assets (Liabilities) | \$ 18,442 | \$ (810) | \$ - | \$ 17,228 | \$ 34,860 |

Fair Value of Derivative Instruments
June 30, 2010

I&M

| Balance Sheet Location | Risk Management Contracts | Hedging Contracts | | Other (a) (b) | Total |
|---------------------------------------|---------------------------|-------------------|------------------------------------|---------------|-----------|
| | Commodity | Commodity | Interest Rate and Foreign Currency | | |
| | | | (a) | | |
| | | | | | |
| Current Risk Management Assets | \$ 173,559 | \$ 1,461 | \$ - | \$ (142,217) | \$ 32,803 |
| Long-term Risk Management Assets | 88,905 | 124 | - | (52,852) | 36,177 |
| Total Assets | 262,464 | 1,585 | - | (195,069) | 68,980 |
| Current Risk Management Liabilities | 161,289 | 2,586 | - | (149,767) | 14,108 |
| Long-term Risk Management Liabilities | 71,618 | 239 | - | (60,608) | 11,249 |
| Total Liabilities | 232,907 | 2,825 | - | (210,375) | 25,357 |
| Total MTM Derivative Contract Net | | | | | |
| Assets (Liabilities) | \$ 29,557 | \$ (1,240) | \$ - | \$ 15,306 | \$ 43,623 |

Fair Value of Derivative Instruments
December 31, 2009

I&M

| Balance Sheet Location | Risk Management Contracts | | Hedging Contracts | | Other (a) (b) | Total |
|----------------------------------|---------------------------|-----------|------------------------------------|---------------|---------------|-------|
| | Commodity | Commodity | Interest Rate and Foreign Currency | (a) | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| (in thousands) | | | | | | |
| Current Risk Management Assets | \$ 167,847 | \$ 1,839 | \$ - | \$ (135,248) | \$ 34,438 | |
| Long-term Risk Management Assets | 72,127 | - | - | (42,993) | 29,134 | |
| Total Assets | 239,974 | 1,839 | - | (178,241) | 63,572 | |

| | | | | | |
|-------------------------|-----------|-----------|------|------------|-----------|
| Current Risk Management | | | | | |
| Liabilities | 156,561 | 2,596 | - | (145,721) | 13,436 |
| Long-term Risk | | | | | |
| Management Liabilities | 60,217 | 41 | - | (49,872) | 10,386 |
| Total Liabilities | 216,778 | 2,637 | - | (195,593) | 23,822 |
| Total MTM Derivative | | | | | |
| Contract Net | | | | | |
| Assets (Liabilities) | \$ 23,196 | \$ (798) | \$ - | \$ 17,352 | \$ 39,750 |

Fair Value of Derivative Instruments
June 30, 2010

OPCo

| Balance Sheet Location | Risk Management Contracts | Hedging Contracts | | | Total |
|---------------------------------------|---------------------------|-------------------|------------------------------------|---------------|-----------|
| | Commodity | Commodity | Interest Rate and Foreign Currency | Other (a) (b) | |
| | | | (a) | | |
| | | | | | |
| (in thousands) | | | | | |
| Current Risk Management Assets | \$ 245,522 | \$ 1,683 | \$ - | \$ (207,134) | \$ 40,071 |
| Long-term Risk Management Assets | 104,381 | 142 | - | (73,017) | 31,506 |
| Total Assets | 349,903 | 1,825 | - | (280,151) | 71,577 |
| Current Risk Management Liabilities | 232,950 | 2,973 | - | (215,951) | 19,972 |
| Long-term Risk Management Liabilities | 95,164 | 285 | - | (82,048) | 13,401 |
| Total Liabilities | 328,114 | 3,258 | - | (297,999) | 33,373 |
| Total MTM Derivative Contract Net | | | | | |
| Assets (Liabilities) | \$ 21,789 | \$ (1,433) | \$ - | \$ 17,848 | \$ 38,204 |

Fair Value of Derivative Instruments
December 31, 2009

OPCo

| Balance Sheet Location | Risk Management Contracts | | Hedging Contracts | | Other (a) (b) | Total |
|----------------------------------|---------------------------|-----------|------------------------------------|---------------|---------------|-------|
| | Commodity | Commodity | Interest Rate and Foreign Currency | (a) | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| (in thousands) | | | | | | |
| Current Risk Management Assets | \$ 255,179 | \$ 2,199 | \$ - | \$ (207,330) | \$ 50,048 | |
| Long-term Risk Management Assets | 88,064 | - | - | (60,061) | 28,003 | |
| Total Assets | 343,243 | 2,199 | - | (267,391) | 78,051 | |

| | | | | | |
|-------------------------|-----------|-----------|------|------------|-----------|
| Current Risk Management | | | | | |
| Liabilities | 240,877 | 2,998 | - | (219,484) | 24,391 |
| Long-term Risk | | | | | |
| Management Liabilities | 81,186 | 47 | - | (68,723) | 12,510 |
| Total Liabilities | 322,063 | 3,045 | - | (288,207) | 36,901 |
| Total MTM Derivative | | | | | |
| Contract Net | | | | | |
| Assets (Liabilities) | \$ 21,180 | \$ (846) | \$ - | \$ 20,816 | \$ 41,150 |

Fair Value of Derivative Instruments
June 30, 2010

| | | | | | | |
|---------------------------------------|---------------------------|-----------|-------------------|------------------------------------|--|----------|
| PSO | | | | | | |
| | Risk Management Contracts | | Hedging Contracts | | | |
| | | | | Interest Rate and Foreign Currency | | |
| | Commodity | Commodity | | | | |
| Balance Sheet Location | (a) | (a) | (a) | Other (a) (b) | | Total |
| (in thousands) | | | | | | |
| Current Risk Management Assets | \$ 10,056 | \$ 59 | \$ - | \$ (7,507) | | \$ 2,608 |
| Long-term Risk Management Assets | 2,105 | - | - | (2,072) | | 33 |
| Total Assets | 12,161 | 59 | - | (9,579) | | 2,641 |
| Current Risk Management Liabilities | 7,769 | 151 | - | (7,533) | | 387 |
| Long-term Risk Management Liabilities | 2,210 | 40 | - | (2,138) | | 112 |
| Total Liabilities | 9,979 | 191 | - | (9,671) | | 499 |
| Total MTM Derivative Contract Net | | | | | | |
| Assets (Liabilities) | \$ 2,182 | \$ (132) | \$ - | \$ 92 | | \$ 2,142 |

Fair Value of Derivative Instruments
December 31, 2009

| | | | | | | |
|----------------------------------|---------------------------|-----------|-------------------|------------------------------------|--|----------|
| PSO | | | | | | |
| | Risk Management Contracts | | Hedging Contracts | | | |
| | | | | Interest Rate and Foreign Currency | | |
| | Commodity | Commodity | | | | |
| Balance Sheet Location | (a) | (a) | (a) | Other (a) (b) | | Total |
| (in thousands) | | | | | | |
| Current Risk Management Assets | \$ 14,885 | \$ 179 | \$ - | \$ (12,688) | | \$ 2,376 |
| Long-term Risk Management Assets | 2,640 | - | - | (2,590) | | 50 |
| Total Assets | 17,525 | 179 | - | (15,278) | | 2,426 |
| | 14,981 | 301 | - | (12,703) | | 2,579 |

Current Risk Management

Liabilities

Long-term Risk Management

| | | | | | |
|-------------------|--------|-----|---|----------|-------|
| Liabilities | 2,913 | - | - | (2,769) | 144 |
| Total Liabilities | 17,894 | 301 | - | (15,472) | 2,723 |

Total MTM Derivative Contract

| | | | | | | | | | | |
|----------------------|----|-------|----|-------|----|---|----|-----|----|-------|
| Net | | | | | | | | | | |
| Assets (Liabilities) | \$ | (369) | \$ | (122) | \$ | - | \$ | 194 | \$ | (297) |

Fair Value of Derivative Instruments
June 30, 2010

SWEPCo

| Balance Sheet Location | Risk Management Contracts | | Hedging Contracts | | Other (a) (b) | Total |
|---------------------------------------|---------------------------|---------------|---|-------------|---------------|-------|
| | Commodity (a) | Commodity (a) | Interest Rate and Foreign Currency (a) (in thousands) | | | |
| Current Risk Management Assets | \$ 14,989 | \$ 47 | \$ 2 | \$ (12,841) | \$ 2,197 | |
| Long-term Risk Management Assets | 3,655 | - | - | (3,606) | 49 | |
| Total Assets | 18,644 | 47 | 2 | (16,447) | 2,246 | |
| Current Risk Management Liabilities | 13,596 | 66 | 232 | (12,883) | 1,011 | |
| Long-term Risk Management Liabilities | 3,948 | 37 | 1 | (3,690) | 296 | |
| Total Liabilities | 17,544 | 103 | 233 | (16,573) | 1,307 | |
| Total MTM Derivative Contract Net | | | | | | |
| Assets (Liabilities) | \$ 1,100 | \$ (56) | \$ (231) | \$ 126 | \$ 939 | |

Fair Value of Derivative Instruments
December 31, 2009

SWEPCo

| Balance Sheet Location | Risk Management Contracts | | Hedging Contracts | | Other (a) (b) | Total |
|---------------------------------------|---------------------------|---------------|---|-------------|---------------|-------|
| | Commodity (a) | Commodity (a) | Interest Rate and Foreign Currency (a) (in thousands) | | | |
| Current Risk Management Assets | \$ 22,847 | \$ 169 | \$ 42 | \$ (20,009) | \$ 3,049 | |
| Long-term Risk Management Assets | 4,145 | - | 5 | (4,066) | 84 | |
| Total Assets | 26,992 | 169 | 47 | (24,075) | 3,133 | |
| Current Risk Management Liabilities | 20,788 | - | 89 | (20,033) | 844 | |
| Long-term Risk Management Liabilities | 4,568 | - | - | (4,347) | 221 | |
| Total Liabilities | 25,356 | - | 89 | (24,380) | 1,065 | |

Total MTM Derivative Contract
Net

| | | | | | | | | | | |
|----------------------|----|-------|----|-----|----|------|----|-----|----|-------|
| Assets (Liabilities) | \$ | 1,636 | \$ | 169 | \$ | (42) | \$ | 305 | \$ | 2,068 |
|----------------------|----|-------|----|-----|----|------|----|-----|----|-------|

- (a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the Condensed Balance Sheets on a net basis in accordance with the accounting guidance for “Derivatives and Hedging.”
- (b) Amounts represent counterparty netting of risk management and hedging contracts, associated cash collateral in accordance with the accounting guidance for “Derivatives and Hedging” and dedesignated risk management contracts.

The tables below presents the Registrant Subsidiaries' activity of derivative risk management contracts for the three and six months ended June 30, 2010 and 2009:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended June 30, 2010

| Location of Gain (Loss) | APCo | CSPCo | I&M (in thousands) | OPCo | PSO | SWEPCo |
|--|-------------|-------------|-----------------------|-------------|--------|----------|
| Electric Generation, Transmission and Distribution | | | | | | |
| Revenues | \$ (1,693) | \$ 3,469 | \$ 2,503 | \$ 2,010 | \$ 347 | \$ 613 |
| Sales to AEP Affiliates | 786 | 113 | 102 | 2,156 | (121) | (229) |
| Regulatory Assets (a) | (1,046) | (5,225) | (2,238) | (5,754) | (25) | 120 |
| Regulatory Liabilities (a) | (834) | - | (4,393) | - | 126 | 1,524 |
| Total Gain (Loss) on Risk Management Contracts | \$ (2,787) | \$ (1,643) | \$ (4,026) | \$ (1,588) | \$ 327 | \$ 2,028 |

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended June 30, 2009

| Location of Gain (Loss) | APCo | CSPCo | I&M (in thousands) | OPCo | PSO | SWEPCo |
|--|----------|----------|-----------------------|-----------|-----------|-----------|
| Electric Generation, Transmission and Distribution | | | | | | |
| Revenues | \$ 1,184 | \$ 9,261 | \$ 6,028 | \$ 10,804 | \$ (407) | \$ (305) |
| Sales to AEP Affiliates | (306) | (393) | (447) | 1,721 | 837 | 806 |
| Regulatory Assets (a) | (3,267) | (5,100) | (3,327) | (6,060) | - | (62) |
| Regulatory Liabilities (a) | 5,010 | (1,162) | 1,617 | (1,439) | (1,339) | (324) |
| Total Gain (Loss) on Risk Management Contracts | \$ 2,621 | \$ 2,606 | \$ 3,871 | \$ 5,026 | \$ (909) | \$ 115 |

Amount of Gain (Loss) Recognized
on Risk Management Contracts
For the Six Months Ended June 30, 2010

| APCo | CSPCo | I&M | OPCo | PSO | SWEPCo |
|------|-------|-----|------|-----|--------|
|------|-------|-----|------|-----|--------|

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| Location of Gain (Loss) | (in thousands) | | | | | |
|--|----------------|-----------|-----------|-----------|-----------|----------|
| Electric Generation, Transmission and Distribution | | | | | | |
| Revenues | \$ 2,480 | \$ 13,076 | \$ 9,388 | \$ 12,231 | \$ 1,030 | \$ 1,402 |
| Sales to AEP | | | | | | |
| Affiliates | (1,575) | (1,449) | (1,341) | 2,409 | (297) | (538) |
| Regulatory Assets | | | | | | |
| (a) | - | (1,544) | - | (1,690) | 306 | 73 |
| Regulatory | | | | | | |
| Liabilities (a) | 15,147 | - | 8,461 | 29 | 2,764 | 513 |
| Total Gain (Loss) on Risk Management | | | | | | |
| Contracts | \$ 16,052 | \$ 10,083 | \$ 16,508 | \$ 12,979 | \$ 3,803 | \$ 1,450 |
| Amount of Gain (Loss) Recognized on Risk Management Contracts For the Six Months Ended June 30, 2009 | | | | | | |
| Location of Gain (Loss) | APCo | CSPCo | I&M | OPCo | PSO | SWEPCo |
| | (in thousands) | | | | | |
| Electric Generation, Transmission and Distribution | | | | | | |
| Revenues | \$ 10,971 | \$ 20,006 | \$ 24,206 | \$ 24,298 | \$ 848 | \$ 1,218 |
| Sales to AEP | | | | | | |
| Affiliates | (7,326) | (4,469) | (4,418) | (1,493) | (625) | (975) |
| Regulatory Assets | | | | | | |
| (a) | - | (3,627) | (2,449) | (4,309) | - | (103) |
| Regulatory | | | | | | |
| Liabilities (a) | 14,280 | (2,490) | 978 | (3,084) | (882) | 249 |
| Total Gain (Loss) on Risk Management | | | | | | |
| Contracts | \$ 17,925 | \$ 9,420 | \$ 18,317 | \$ 15,412 | \$ (659) | \$ 389 |

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or non-current on the balance sheet.

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for “Derivatives and Hedging.” Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the Condensed Statements of Income on an accrual basis.

The accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, management designates a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on the Condensed Statements of Income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on the Condensed Statements of Income depending on the relevant facts and circumstances. However, unrealized and some realized gains and losses in regulated jurisdictions (APCo, I&M, PSO, the non-Texas portion of SWEPCo generation and beginning in the second quarter of 2009 the Texas portion of SWEPCo generation) for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with the accounting guidance for “Regulated Operations.” SWEPCo re-applied the accounting guidance for “Regulated Operations” for the generation portion of SWEPCo’s Texas retail jurisdiction effective the second quarter of 2009.

Accounting for Fair Value Hedging Strategies

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof attributable to a particular risk), the Registrant Subsidiaries recognize the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item associated with the hedged risk in Net Income during the period of change.

The Registrant Subsidiaries record realized and unrealized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on the Condensed Statements of Income. During the three and six months ended June 30, 2010 and 2009, the Registrant Subsidiaries did not employ any fair value hedging strategies.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), the Registrant Subsidiaries initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the Condensed Balance Sheets until the period the hedged item affects Net Income. The Registrant Subsidiaries recognize any hedge ineffectiveness in Net Income immediately during the period of change, except in regulated jurisdictions where hedge ineffectiveness is recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivative contracts for the purchase and sale of electricity, coal, heating oil and natural gas designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on the Condensed Statements of Income, or in Regulatory Assets or Regulatory Liabilities on the Condensed Balance Sheets, depending on the specific nature of the risk being hedged. During the three and six months ended June 30, 2010 and 2009, APCo, CSPCo, I&M and OPCo designated commodity derivatives as cash flow hedges.

The Registrant Subsidiaries reclassify gains and losses on financial fuel derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on the Condensed Balance Sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the Condensed Statements of Income. During the three and six months ended June 30, 2010, the Registrant Subsidiaries designated cash flow hedging strategies of forecasted fuel purchases.

The Registrant Subsidiaries reclassify gains and losses on interest rate derivative hedges related to debt financing from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During the three and six months ended June 30, 2010, APCo designated interest rate derivatives as cash flow hedges. During the three and six months ended June 30, 2009, OPCo designated interest rate derivatives as cash flow hedges.

The accumulated gains or losses related to foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on the Condensed Balance Sheets into Depreciation and Amortization expense on the Condensed Statements of Income over the depreciable lives of the fixed assets that were designated as the hedged items in qualifying foreign currency hedging relationships. During the three and six months ended June 30, 2010 and 2009, SWEPCo designated foreign currency derivatives as cash flow hedges.

During the three and six months ended June 30, 2010 and 2009, hedge ineffectiveness was immaterial or nonexistent for all of the hedge strategies disclosed above.

The following tables provides details on designated, effective cash flow hedges included in AOCI on the Condensed Balance Sheets and the reasons for changes in cash flow hedges for the three and six months ended June 30, 2010 and 2009. All amounts in the following tables are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Three Months Ended June 30, 2010

| Commodity Contracts | APCo | CSPCo | I&M | OPCo | PSO | SWEPCo |
|--|------------|------------|------------|------------|----------|------------|
| (in thousands) | | | | | | |
| Balance in AOCI as of March 31, 2010 | \$ (2,451) | \$ (1,407) | \$ (1,418) | \$ (1,543) | \$ (8) | \$ 100 |
| Changes in Fair Value Recognized in AOCI | 642 | 380 | 388 | 370 | (191) | (99) |
| Amount of (Gain) or Loss Reclassified | | | | | | |
| from AOCI to Income Statements/within | | | | | | |
| Balance Sheet: | | | | | | |
| Electric Generation, Transmission, and | | | | | | |
| Distribution Revenues | 31 | 79 | 66 | 91 | - | - |
| Fuel and Other Consumables Used for | | | | | | |
| Electric Generation | - | - | - | (4) | 150 | - |
| Purchased Electricity for Resale | 65 | 168 | 139 | 193 | - | - |
| Other Operation Expense | (18) | (11) | (11) | (15) | (13) | (16) |
| Maintenance Expense | (22) | (6) | (9) | (11) | (8) | (8) |
| Property, Plant and Equipment | (24) | (10) | (12) | (17) | (14) | (10) |
| Regulatory Assets (a) | 340 | - | 44 | - | - | - |
| Regulatory Liabilities (a) | - | - | - | (5) | - | - |
| Balance in AOCI as of June 30, 2010 | \$ (1,437) | \$ (807) | \$ (813) | \$ (941) | \$ (84) | \$ (33) |
| Interest Rate and Foreign Currency | | | | | | |
| Contracts | APCo | CSPCo | I&M | OPCo | PSO | SWEPCo |
| (in thousands) | | | | | | |
| Balance in AOCI as of March 31, 2010 | \$ (6,488) | \$ - | \$ (9,262) | \$ 11,832 | \$ (475) | \$ (4,947) |
| Changes in Fair Value Recognized in AOCI | (2,229) | - | - | - | - | (96) |
| Amount of (Gain) or Loss Reclassified | | | | | | |
| from AOCI to Income Statements/within | | | | | | |
| Balance Sheet: | | | | | | |
| Depreciation and Amortization | | | | | | |
| Expense | - | - | - | 1 | - | - |
| Other Operation Expense | - | - | - | - | - | 24 |
| Interest Expense | 419 | - | 251 | (341) | 32 | 207 |

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| | | | | | | |
|--|----------------|------------|-------------|-----------|----------|------------|
| Balance in AOCI as of June 30, 2010 | \$ (8,298) | \$ - | \$ (9,011) | \$ 11,492 | \$ (443) | \$ (4,812) |
| Total Contracts | APCo | CSPCo | I&M | OPCo | PSO | SWEPCo |
| | (in thousands) | | | | | |
| Balance in AOCI as of March 31, 2010 | \$ (8,939) | \$ (1,407) | \$ (10,680) | \$ 10,289 | \$ (483) | \$ (4,847) |
| Changes in Fair Value Recognized in AOCI | (1,587) | 380 | 388 | 370 | (191) | (195) |
| Amount of (Gain) or Loss Reclassified | | | | | | |
| from AOCI to Income Statements/within | | | | | | |
| Balance Sheet: | | | | | | |
| Electric Generation, Transmission, and Distribution Revenues | 31 | 79 | 66 | 91 | - | - |
| Fuel and Other Consumables Used for Electric Generation | - | - | - | (4) | 150 | - |
| Purchased Electricity for Resale | 65 | 168 | 139 | 193 | - | - |
| Other Operation Expense | 401 | (11) | 240 | (356) | 19 | 191 |
| Maintenance Expense | (22) | (6) | (9) | (11) | (8) | (8) |
| Depreciation and Amortization Expense | - | - | - | 1 | - | - |
| Interest Expense | - | - | - | - | - | 24 |
| Property, Plant and Equipment | (24) | (10) | (12) | (17) | (14) | (10) |
| Regulatory Assets (a) | 340 | - | 44 | - | - | - |
| Regulatory Liabilities (a) | - | - | - | (5) | - | - |
| Balance in AOCI as of June 30, 2010 | \$ (9,735) | \$ (807) | \$ (9,824) | \$ 10,551 | \$ (527) | \$ (4,845) |

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Three Months Ended June 30, 2009

| Commodity Contracts | APCo | CSPCo | I&M | OPCo | PSO | SWEPCo |
|--|------------|----------|-------------|-----------|----------|------------|
| (in thousands) | | | | | | |
| Balance in AOCI as of March 31, 2009 | \$ 4,066 | \$ 2,162 | \$ 2,091 | \$ 2,669 | \$ (24) | \$ (21) |
| Changes in Fair Value Recognized in AOCI | (207) | (143) | (119) | (115) | 155 | 166 |
| Amount of (Gain) or Loss Reclassified | | | | | | |
| from AOCI to Income Statements/within | | | | | | |
| Balance Sheet: | | | | | | |
| Electric Generation, Transmission, and | | | | | | |
| Distribution Revenues | (458) | (1,158) | (885) | (1,434) | - | - |
| Fuel and Other Consumables Used for | | | | | | |
| Electric Generation | (6) | (4) | (4) | (5) | (3) | (3) |
| Purchased Electricity for Resale | 132 | 334 | 255 | 413 | - | - |
| Other Operation Expense | - | - | - | - | - | - |
| Maintenance Expense | - | - | - | - | - | - |
| Property, Plant and Equipment | (3) | (2) | (1) | (2) | (1) | (1) |
| Regulatory Assets (a) | 497 | - | 68 | - | - | - |
| Regulatory Liabilities (a) | (1,725) | - | (235) | - | - | - |
| Balance in AOCI as of June 30, 2009 | \$ 2,296 | \$ 1,189 | \$ 1,170 | \$ 1,526 | \$ 127 | \$ 141 |
| Interest Rate and Foreign Currency | | | | | | |
| Contracts | APCo | CSPCo | I&M | OPCo | PSO | SWEPCo |
| (in thousands) | | | | | | |
| Balance in AOCI as of March 31, 2009 | \$ (7,702) | \$ - | \$ (10,271) | \$ 2,039 | \$ (658) | \$ (5,808) |
| Changes in Fair Value Recognized in AOCI | - | - | - | 14,690 | - | 104 |
| Amount of (Gain) or Loss Reclassified | | | | | | |
| from AOCI to Income Statements/within | | | | | | |
| Balance Sheet: | | | | | | |
| Depreciation and Amortization | | | | | | |
| Expense | - | - | - | 1 | - | - |
| Interest Expense | 417 | - | 254 | (68) | 45 | 207 |
| | \$ (7,285) | \$ - | \$ (10,017) | \$ 16,662 | \$ (613) | \$ (5,497) |

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| | | | | | | |
|--|------------|----------|------------|-----------|----------|------------|
| Balance in AOCI as of June 30, 2009 | | | | | | |
| Total Contracts | APCo | CSPCo | I&M | OPCo | PSO | SWEPCo |
| (in thousands) | | | | | | |
| Balance in AOCI as of March 31, 2009 | \$ (3,636) | \$ 2,162 | \$ (8,180) | \$ 4,708 | \$ (682) | \$ (5,829) |
| Changes in Fair Value Recognized in AOCI | (207) | (143) | (119) | 14,575 | 155 | 270 |
| Amount of (Gain) or Loss Reclassified | | | | | | |
| from AOCI to Income Statements/within | | | | | | |
| Balance Sheet: | | | | | | |
| Electric Generation, Transmission, and | | | | | | |
| Distribution Revenues | (458) | (1,158) | (885) | (1,434) | - | - |
| Fuel and Other Consumables Used for | | | | | | |
| Electric Generation | (6) | (4) | (4) | (5) | (3) | (3) |
| Purchased Electricity for Resale | 132 | 334 | 255 | 413 | - | - |
| Other Operation Expense | - | - | - | - | - | - |
| Maintenance Expense | - | - | - | - | - | - |
| Depreciation and Amortization | | | | | | |
| Expense | - | - | - | 1 | - | - |
| Interest Expense | 417 | - | 254 | (68) | 45 | 207 |
| Property, Plant and Equipment | (3) | (2) | (1) | (2) | (1) | (1) |
| Regulatory Assets (a) | 497 | - | 68 | - | - | - |
| Regulatory Liabilities (a) | (1,725) | - | (235) | - | - | - |
| Balance in AOCI as of June 30, 2009 | \$ (4,989) | \$ 1,189 | \$ (8,847) | \$ 18,188 | \$ (486) | \$ (5,356) |

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Six Months Ended June 30, 2010

| Commodity Contracts | APCo | CSPCo | I&M (in thousands) | OPCo | PSO | SWEPCo |
|--|------------|----------|-----------------------|-----------|----------|------------|
| Balance in AOCI as of December 31, 2009 | \$ (743) | \$ (376) | \$ (382) | \$ (366) | \$ (78) | \$ 112 |
| Changes in Fair Value Recognized in AOCI | (1,857) | (1,077) | (1,083) | (1,300) | (105) | (96) |
| Amount of (Gain) or Loss Reclassified | | | | | | |
| from AOCI to Income Statements/within | | | | | | |
| Balance Sheet: | | | | | | |
| Electric Generation, Transmission, and | | | | | | |
| Distribution Revenues | 57 | 144 | 120 | 167 | - | - |
| Fuel and Other Consumables Used for | | | | | | |
| Electric Generation | - | - | - | (13) | 150 | - |
| Purchased Electricity for Resale | 211 | 550 | 455 | 633 | - | - |
| Other Operation Expense | (24) | (19) | (17) | (20) | (19) | (23) |
| Maintenance Expense | (36) | (12) | (14) | (15) | (12) | (12) |
| Property, Plant and Equipment | (33) | (17) | (17) | (22) | (20) | (14) |
| Regulatory Assets (a) | 988 | - | 125 | - | - | - |
| Regulatory Liabilities (a) | - | - | - | (5) | - | - |
| Balance in AOCI as of June 30, 2010 | \$ (1,437) | \$ (807) | \$ (813) | \$ (941) | \$ (84) | \$ (33) |
| Interest Rate and Foreign Currency | | | | | | |
| Contracts | APCo | CSPCo | I&M (in thousands) | OPCo | PSO | SWEPCo |
| Balance in AOCI as of December 31, 2009 | \$ (6,450) | \$ - | \$ (9,514) | \$ 12,172 | \$ (521) | \$ (5,047) |
| Changes in Fair Value Recognized in AOCI | (2,685) | - | - | - | - | (203) |
| Amount of (Gain) or Loss Reclassified | | | | | | |
| from AOCI to Income Statements/within | | | | | | |
| Balance Sheet: | | | | | | |
| Depreciation and Amortization | | | | | | |
| Expense | - | - | - | 2 | - | - |
| Other Operation Expense | - | - | - | - | - | 24 |
| Interest Expense | 837 | - | 503 | (682) | 78 | 414 |
| Balance in AOCI as of June 30, 2010 | \$ (8,298) | \$ - | \$ (9,011) | \$ 11,492 | \$ (443) | \$ (4,812) |

| Total Contracts | APCo | CSPCo | I&M | OPCo | PSO | SWEPCo |
|--|------------|----------|------------|-----------|----------|------------|
| (in thousands) | | | | | | |
| Balance in AOCI as of December 31, 2009 | \$ (7,193) | \$ (376) | \$ (9,896) | \$ 11,806 | \$ (599) | \$ (4,935) |
| Changes in Fair Value Recognized in AOCI | (4,542) | (1,077) | (1,083) | (1,300) | (105) | (299) |
| Amount of (Gain) or Loss Reclassified | | | | | | |
| from AOCI to Income Statements/within Balance Sheet: | | | | | | |
| Electric Generation, Transmission, and Distribution Revenues | 57 | 144 | 120 | 167 | - | - |
| Fuel and Other Consumables Used for Electric Generation | - | - | - | (13) | 150 | - |
| Purchased Electricity for Resale | 211 | 550 | 455 | 633 | - | - |
| Other Operation Expense | (24) | (19) | (17) | (20) | (19) | 1 |
| Maintenance Expense | (36) | (12) | (14) | (15) | (12) | (12) |
| Depreciation and Amortization Expense | - | - | - | 2 | - | - |
| Interest Expense | 837 | - | 503 | (682) | 78 | 414 |
| Property, Plant and Equipment | (33) | (17) | (17) | (22) | (20) | (14) |
| Regulatory Assets (a) | 988 | - | 125 | - | - | - |
| Regulatory Liabilities (a) | - | - | - | (5) | - | - |
| Balance in AOCI as of June 30, 2010 | \$ (9,735) | \$ (807) | \$ (9,824) | \$ 10,551 | \$ (527) | \$ (4,845) |

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Six Months Ended June 30, 2009

| Commodity Contracts | APCo | CSPCo | I&M | OPCo | PSO | SWEPCo |
|--|------------|----------|-------------|-----------|----------|------------|
| (in thousands) | | | | | | |
| Balance in AOCI as of December 31, 2008 | \$ 2,726 | \$ 1,531 | \$ 1,482 | \$ 1,898 | \$ - | \$ - |
| Changes in Fair Value Recognized in AOCI | 173 | (25) | (6) | 21 | 131 | 145 |
| Amount of (Gain) or Loss Reclassified | | | | | | |
| from AOCI to Income Statements/within | | | | | | |
| Balance Sheet: | | | | | | |
| Electric Generation, Transmission, and | | | | | | |
| Distribution Revenues | (709) | (1,771) | (1,389) | (2,193) | - | - |
| Fuel and Other Consumables Used for | | | | | | |
| Electric Generation | (6) | (4) | (4) | (5) | (3) | (3) |
| Purchased Electricity for Resale | 594 | 1,460 | 1,181 | 1,807 | - | - |
| Other Operation Expense | - | - | - | - | - | - |
| Maintenance Expense | - | - | - | - | - | - |
| Property, Plant and Equipment | (3) | (2) | (1) | (2) | (1) | (1) |
| Regulatory Assets (a) | 2,136 | - | 231 | - | - | - |
| Regulatory Liabilities (a) | (2,615) | - | (324) | - | - | - |
| Balance in AOCI as of June 30, 2009 | \$ 2,296 | \$ 1,189 | \$ 1,170 | \$ 1,526 | \$ 127 | \$ 141 |
| Interest Rate and Foreign Currency | | | | | | |
| Contracts | APCo | CSPCo | I&M | OPCo | PSO | SWEPCo |
| (in thousands) | | | | | | |
| Balance in AOCI as of December 31, 2008 | \$ (8,118) | \$ - | \$ (10,521) | \$ 1,752 | \$ (704) | \$ (5,924) |
| Changes in Fair Value Recognized in AOCI | - | - | - | 14,953 | - | 13 |
| Amount of (Gain) or Loss Reclassified | | | | | | |
| from AOCI to Income Statements/within | | | | | | |
| Balance Sheet: | | | | | | |
| Depreciation and Amortization | | | | | | |
| Expense | - | - | (2) | 2 | - | - |
| Interest Expense | 833 | - | 506 | (45) | 91 | 414 |
| | \$ (7,285) | \$ - | \$ (10,017) | \$ 16,662 | \$ (613) | \$ (5,497) |

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| Balance in AOCI as of June 30, 2009 | | | | | | |
|--|------------|----------|------------|-----------|----------|------------|
| Total Contracts | APCo | CSPCo | I&M | OPCo | PSO | SWEPCo |
| (in thousands) | | | | | | |
| Balance in AOCI as of December 31, 2008 | \$ (5,392) | \$ 1,531 | \$ (9,039) | \$ 3,650 | \$ (704) | \$ (5,924) |
| Changes in Fair Value Recognized in AOCI | 173 | (25) | (6) | 14,974 | 131 | 158 |
| Amount of (Gain) or Loss Reclassified | | | | | | |
| from AOCI to Income Statements/within | | | | | | |
| Balance Sheet: | | | | | | |
| Electric Generation, Transmission, and | | | | | | |
| Distribution Revenues | (709) | (1,771) | (1,389) | (2,193) | - | - |
| Fuel and Other Consumables Used for | | | | | | |
| Electric Generation | (6) | (4) | (4) | (5) | (3) | (3) |
| Purchased Electricity for Resale | 594 | 1,460 | 1,181 | 1,807 | - | - |
| Other Operation Expense | - | - | - | - | - | - |
| Maintenance Expense | - | - | - | - | - | - |
| Depreciation and Amortization | | | | | | |
| Expense | - | - | (2) | 2 | - | - |
| Interest Expense | 833 | - | 506 | (45) | 91 | 414 |
| Property, Plant and Equipment | (3) | (2) | (1) | (2) | (1) | (1) |
| Regulatory Assets (a) | 2,136 | - | 231 | - | - | - |
| Regulatory Liabilities (a) | (2,615) | - | (324) | - | - | - |
| Balance in AOCI as of June 30, 2009 | \$ (4,989) | \$ 1,189 | \$ (8,847) | \$ 18,188 | \$ (486) | \$ (5,356) |

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or non-current on the balance sheets.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the Condensed Balance Sheets at June 30, 2010 and December 31, 2009 were:

Impact of Cash Flow Hedges on the Registrant Subsidiaries'
Condensed Balance Sheets
June 30, 2010

| Company | Hedging Assets (a) | | Hedging Liabilities (a) | | AOCI Gain (Loss) Net of Tax | |
|---------|--------------------|------------------------------------|-------------------------|------------------------------------|-----------------------------|------------------------------------|
| | Commodity | Interest Rate and Foreign Currency | Commodity | Interest Rate and Foreign Currency | Commodity | Interest Rate and Foreign Currency |
| | | | (in thousands) | | | |
| APCo | \$ 332 | \$ - | \$ (2,517) | \$ - | \$ (1,437) | \$ (8,298) |
| CSPCo | 188 | - | (1,413) | - | (807) | - |
| I&M | 189 | - | (1,429) | - | (813) | (9,011) |
| OPCo | 216 | - | (1,649) | - | (941) | 11,492 |
| PSO | 8 | - | (140) | - | (84) | (443) |
| SWEPCo | - | - | (56) | (231) | (33) | (4,812) |

Expected to be Reclassified to
Net Income During the Next
Twelve Months

| Company | Commodity (in thousands) | Interest Rate and Foreign Currency | Maximum Term for Exposure to Variability of Future Cash Flows (in months) |
|---------|-----------------------------|--|--|
| | | | |
| APCo | \$ (1,300) | \$ (1,634) | 18 |
| CSPCo | (733) | - | 18 |
| I&M | (740) | (1,007) | 18 |
| OPCo | (849) | 1,359 | 18 |
| PSO | (58) | (73) | 18 |
| SWEPCo | (10) | (829) | 29 |

Impact of Cash Flow Hedges on the Registrant Subsidiaries'
Condensed Balance Sheets
December 31, 2009

| Company | Hedging Assets (a) | | Hedging Liabilities (a) | | AOCI Gain (Loss) Net of Tax | |
|----------------|--------------------|------------------------------------|-------------------------|------------------------------------|-----------------------------|------------------------------------|
| | Commodity | Interest Rate and Foreign Currency | Commodity | Interest Rate and Foreign Currency | Commodity | Interest Rate and Foreign Currency |
| (in thousands) | | | | | | |
| APCo | \$ 1,999 | \$ - | \$ (3,542) | \$ - | \$ (743) | \$ (6,450) |
| CSPCo | 984 | - | (1,794) | - | (376) | - |
| I&M | 1,011 | - | (1,809) | - | (382) | (9,514) |
| OPCo | 1,242 | - | (2,088) | - | (366) | 12,172 |
| PSO | 178 | - | (300) | - | (78) | (521) |
| SWEPCo | 168 | 5 | - | (46) | 112 | (5,047) |

Expected to be Reclassified to
Net Income During the Next
Twelve Months

| Company | Commodity | Interest Rate and Foreign Currency |
|----------------|-----------|------------------------------------|
| (in thousands) | | |
| APCo | \$ (691) | \$ (1,301) |
| CSPCo | (349) | - |
| I&M | (358) | (1,007) |
| OPCo | (335) | 1,359 |
| PSO | (79) | (114) |
| SWEPCo | 111 | (829) |

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on the Condensed Balance Sheets.

The actual amounts reclassified from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes.

Credit Risk

AEPSC, on behalf of the Registrant Subsidiaries, limits credit risk in their wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. AEPSC, on behalf of the Registrant Subsidiaries, uses Moody's, S&P and current market-based qualitative and quantitative data to assess the financial health of counterparties on an ongoing basis. If an external rating is not available, an internal rating is generated utilizing a quantitative tool developed by Moody's to estimate probability of default that corresponds to an implied external agency credit rating.

AEPSC, on behalf of the Registrant Subsidiaries, uses standardized master agreements which may include collateral requirements. These master agreements facilitate the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's credit policy. In addition, collateral agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Under a limited number of derivative and non-derivative counterparty contracts primarily related to pre-2002 risk management activities and under the tariffs of the RTOs and Independent System Operators (ISOs), the Registrant Subsidiaries are obligated to post an amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. Management does not anticipate a downgrade below investment grade. The following tables represent the Registrant Subsidiaries' aggregate fair value of such derivative contracts, the amount of collateral the Registrant Subsidiaries would have been required to post for all derivative and non-derivative contracts if the credit ratings had declined below investment grade and how much was attributable to RTO and ISO activities as of June 30, 2010 and December 31, 2009:

June 30, 2010

| Company | Liabilities for Derivative Contracts with Credit Downgrade Triggers | Amount of Collateral the Registrant Subsidiaries Would Have Been Required to Post (in thousands) | Amount Attributable to RTO and ISO Activities |
|---------|--|--|--|
| APCo | \$ 6,654 | \$ 4,279 | \$ 4,279 |
| CSPCo | 3,764 | 2,421 | 2,421 |
| I&M | 3,797 | 2,442 | 2,442 |
| OPCo | 4,332 | 2,786 | 2,786 |
| PSO | 291 | 2,837 | 2,546 |
| SWEPCo | 346 | 3,374 | 3,028 |

As of June 30, 2010, the Registrant Subsidiaries were not required to post any cash collateral.

December 31, 2009

| Company | Liabilities for Derivative Contracts with Credit Downgrade Triggers | Amount of Collateral the Registrant Subsidiaries Would Have Been Required to Post (in thousands) | Amount Attributable to RTO and ISO Activities |
|---------|--|--|--|
| APCo | \$ 2,229 | \$ 8,433 | \$ 7,947 |
| CSPCo | 1,129 | 4,272 | 4,026 |
| I&M | 1,139 | 4,309 | 4,060 |
| OPCo | 1,315 | 4,975 | 4,688 |
| PSO | 689 | 2,772 | 2,083 |
| SWEPCo | 819 | 3,297 | 2,477 |

As of December 31, 2009, the Registrant Subsidiaries were not required to post any collateral.

In addition, a majority of the Registrant Subsidiaries' non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event under outstanding debt in excess of \$50 million. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. Management believes that a non-performance event under these provisions is unlikely. The following tables represent the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, the amount this exposure has been reduced by cash collateral posted by the Registrant Subsidiaries and if a cross-default provision would have been triggered, the settlement amount that would be required after considering the Registrant Subsidiaries' contractual netting arrangements as of June 30, 2010 and December 31, 2009:

June 30, 2010

| Company | Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements | Amount of Cash Collateral Posted (in thousands) | Additional Settlement Liability if Cross Default Provision is Triggered |
|---------|--|---|---|
| APCo | \$ 126,334 | \$ 4,808 | \$ 31,707 |
| CSPCo | 71,471 | 2,720 | 17,937 |
| I&M | 72,079 | 2,744 | 18,089 |
| OPCo | 82,290 | 3,131 | 20,682 |
| PSO | 109 | - | 66 |
| SWEPCo | 366 | - | 313 |

December 31, 2009

| Company | Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements | Amount of Cash Collateral Posted (in thousands) | Additional Settlement Liability if Cross Default Provision is Triggered |
|---------|--|---|---|
| APCo | \$ 154,924 | \$ 3,115 | \$ 33,186 |
| CSPCo | 78,489 | 1,578 | 16,813 |
| I&M | 79,158 | 1,592 | 16,955 |
| OPCo | 91,430 | 1,838 | 19,615 |
| PSO | 40 | - | 40 |
| SWEPCo | 139 | - | 93 |

9. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable

inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

For commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are non-binding in nature but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations and if the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Long-dated and illiquid complex or structured transactions and FTRs can introduce the need for internally developed modeling inputs based upon extrapolations and assumptions of observable market data to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3.

AEP utilizes its trustee's external pricing service in its estimate of the fair value of the underlying investments held in the nuclear trusts. AEP's investment managers review and validate the prices utilized by the trustee to determine fair value. AEP's investment managers perform their own valuation testing to verify the fair values of the securities. AEP receives audit reports of the trustee's operating controls and valuation processes. The trustee uses multiple pricing vendors for the assets held in the trusts. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Fixed income securities do not trade on an exchange and do not have an official closing price. Pricing vendors calculate bond valuations using financial models and matrices. Fixed income securities are typically classified as Level 2 holdings because their valuation inputs are based on observable market data. Observable inputs used for valuing fixed income securities are benchmark yields, reported trades, broker/dealer quotes, issuer spreads, two-sided markets, benchmark securities, bids, offers, reference data and economic events. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments.

Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equities. They are valued based on observable inputs primarily unadjusted quoted prices in active markets for identical assets.

Items classified as Level 2 are primarily investments in individual fixed income securities. These fixed income securities are valued using models with input data as follows:

| Type of Input | Type of Fixed Income Security | | |
|------------------------|-------------------------------|-----------|-----------------|
| | United States | Corporate | State and Local |
| | Government | Debt | Government |
| Benchmark Yields | X | X | X |
| Broker Quotes | X | X | X |
| Discount Margins | X | X | |
| Treasury Market Update | X | | |
| Base Spread | X | X | X |
| Corporate Actions | | X | |
| Ratings Agency Updates | | X | X |

Prepayment
Schedule and
History

X

Yield Adjustments X

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of Long-term Debt for the Registrant Subsidiaries as of June 30, 2010 and December 31, 2009 are summarized in the following table:

| Company | June 30, 2010 | | December 31, 2009 | |
|---------|----------------|--------------|-------------------|--------------|
| | Book Value | Fair Value | Book Value | Fair Value |
| | (in thousands) | | | |
| APCo | \$ 3,560,776 | \$ 3,853,884 | \$ 3,477,306 | \$ 3,699,373 |
| CSPCo | 1,588,673 | 1,726,413 | 1,536,393 | 1,616,857 |
| I&M | 2,118,674 | 2,291,479 | 2,077,906 | 2,192,854 |
| OPCo | 2,929,248 | 3,145,855 | 3,242,505 | 3,380,084 |
| PSO | 968,851 | 1,051,083 | 968,121 | 1,007,183 |
| SWEPCo | 1,769,394 | 1,879,630 | 1,474,153 | 1,554,165 |

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions allow I&M to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above when purchased).
- Maximum percentage invested in a specific type of investment.
- Prohibition of investment in obligations of AEP or its affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.
- Target asset allocation is 50% fixed income and 50% equity securities.

I&M maintains trust records for each regulatory jurisdiction. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification and other prudent investment objectives.

I&M records securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF at fair value. I&M classifies securities in the trust funds as available-for-sale due to their long-term purpose. The assessment of whether an investment in a debt security has suffered an other-than-temporary impairment is based on whether the investor has the intent to sell or more likely than not will be required to sell the debt security before recovery of its amortized costs. The assessment of whether an investment in an equity security has suffered an other-than-temporary impairment, among other things, is based on whether the investor has the ability and intent to hold the investment to recover its value. Other-than-temporary impairments for investments in both debt and equity securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the equity and debt investments held in these trusts and generally intends to sell debt securities in an unrealized loss position as part of a tax optimization strategy. I&M records unrealized gains and other-than-temporary impairments from securities in

these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. The gains, losses or other-than-temporary impairments shown below did not affect earnings or AOCI. The trust assets are recorded by jurisdiction and may not be used for another jurisdiction's liabilities. Regulatory approval is required to withdraw decommissioning funds.

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The following is a summary of nuclear trust fund investments at June 30, 2010 and December 31, 2009:

| | June 30, 2010 | | | December 31, 2009 | | |
|---|----------------------------|------------------------------|---|----------------------------|------------------------------|---|
| | Estimated Fair Value | Gross Unrealized Gains | Other-Than- Temporary Impairments | Estimated Fair Value | Gross Unrealized Gains | Other-Than- Temporary Impairments |
| | (in thousands) | | | | | |
| Cash and Cash Equivalents | \$26,512 | \$- | \$- | \$14,412 | \$- | \$- |
| Fixed Income Securities: | | | | | | |
| United States Government | 472,709 | 31,298 | (1,043) | 400,565 | 12,708 | (3,472) |
| Corporate Debt | 60,607 | 6,113 | (6,113) | 57,291 | 4,636 | (2,177) |
| State and Local Government | 316,046 | 2,976 | (258) | 368,930 | 7,924 | 991 |
| Subtotal Fixed Income Securities | 849,362 | 40,387 | (7,414) | 826,786 | 25,268 | (4,658) |
| Equity Securities - Domestic | 515,554 | 193,710 | (121,599) | 550,721 | 234,437 | (119,379) |
| Spent Nuclear Fuel and Decommissioning Trusts | \$1,391,428 | \$234,097 | \$(129,013) | \$1,391,919 | \$259,705 | \$(124,037) |

The following table provides the securities activity within the decommissioning and SNF trusts for the three and six months ended June 30, 2010 and 2009:

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|--------------------------------|------------|------------------------------|------------|
| | 2010 | 2009 | 2010 | 2009 |
| | (in thousands) | | | |
| Proceeds From Investment Sales | \$ 360,185 | \$ 252,941 | \$ 592,263 | \$ 411,027 |
| Purchases of Investments | 369,427 | 263,521 | 617,059 | 441,928 |
| Gross Realized Gains on Investment Sales | 1,022 | 6,471 | 6,350 | 9,353 |
| Gross Realized Losses on Investment Sales | 236 | 460 | 417 | 808 |

The adjusted cost of debt securities was \$809 million and \$801 million as of June 30, 2010 and December 31, 2009, respectively.

The fair value of debt securities held in the nuclear trust funds, summarized by contractual maturities, at June 30, 2010 was as follows:

| | Fair Value of Debt Securities (in thousands) |
|--------------------|---|
| Within 1 year | \$ 11,956 |
| 1 year – 5 years | 262,167 |
| 5 years – 10 years | 303,759 |
| After 10 years | 271,480 |
| Total | \$ 849,362 |

Fair Value Measurements of Financial Assets and Liabilities

The following tables set forth, by level within the fair value hierarchy, the Registrant Subsidiaries' financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2010 and December 31, 2009. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2010

APCo

Level 1 Level 2 Level 3 Other Total

Assets: (in thousands)

Risk Management Assets

| | | | | | |
|------------------------------|----------|------------|-----------|--------------|------------|
| Risk Management Commodity | | | | | |
| Contracts (a) (g) | \$ 2,432 | \$ 418,877 | \$ 21,425 | \$ (346,131) | \$ 96,603 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (a) | - | 2,775 | - | (2,443) | 332 |
| Dedesignated Risk Management | | | | | |
| Contracts (b) | - | - | - | 5,972 | 5,972 |
| Total Risk Management Assets | \$ 2,432 | \$ 421,652 | \$ 21,425 | \$ (342,602) | \$ 102,907 |

Liabilities:

Risk Management Liabilities

| | | | | | |
|-----------------------------------|----------|------------|-----------|--------------|-----------|
| Risk Management Commodity | | | | | |
| Contracts (a) (g) | \$ 2,565 | \$ 395,965 | \$ 10,551 | \$ (368,248) | \$ 40,833 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (a) | - | 4,960 | - | (2,443) | 2,517 |
| DETM Assignment (c) | - | - | - | 1,233 | 1,233 |
| Total Risk Management Liabilities | \$ 2,565 | \$ 400,925 | \$ 10,551 | \$ (369,458) | \$ 44,583 |

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2009

APCo

Level 1 Level 2 Level 3 Other Total

Assets: (in thousands)

| | | | | | |
|-------------------------|--------|------|------|-------|--------|
| Other Cash Deposits (d) | \$ 421 | \$ - | \$ - | \$ 51 | \$ 472 |
|-------------------------|--------|------|------|-------|--------|

Risk Management Assets

| | | | | | |
|------------------------------|----------|------------|-----------|--------------|------------|
| Risk Management Commodity | | | | | |
| Contracts (a) | 2,344 | 449,406 | 12,866 | (360,248) | 104,368 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (a) | - | 3,620 | - | (1,621) | 1,999 |
| Dedesignated Risk Management | | | | | |
| Contracts (b) | - | - | - | 8,730 | 8,730 |
| Total Risk Management Assets | 2,344 | 453,026 | 12,866 | (353,139) | 115,097 |
| Total Assets | \$ 2,765 | \$ 453,026 | \$ 12,866 | \$ (353,088) | \$ 115,569 |

Liabilities:

Risk Management Liabilities

| | | | | | |
|-----------------------------------|----|-------|----|---------|---------------------------------|
| Risk Management Commodity | | | | | |
| Contracts (a) | \$ | 2,648 | \$ | 422,063 | \$ 3,438 \$ (388,265) \$ 39,884 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (a) | | - | | 5,163 | - (1,621) 3,542 |
| DETM Assignment (c) | | - | | - | 2,730 2,730 |
| Total Risk Management Liabilities | \$ | 2,648 | \$ | 427,226 | \$ 3,438 \$ (387,156) \$ 46,156 |

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2010

CSPCo

Level 1 Level 2 Level 3 Other Total

Assets: (in thousands)

Risk Management Assets

| | | | | | |
|------------------------------|----------|------------|-----------|--------------|-----------|
| Risk Management Commodity | | | | | |
| Contracts (a) (g) | \$ 1,376 | \$ 236,523 | \$ 12,120 | \$ (195,420) | \$ 54,599 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (a) | - | 1,559 | - | (1,371) | 188 |
| Dedesignated Risk Management | | | | | |
| Contracts (b) | - | - | - | 3,379 | 3,379 |
| Total Risk Management Assets | \$ 1,376 | \$ 238,082 | \$ 12,120 | \$ (193,412) | \$ 58,166 |

Liabilities:

Risk Management Liabilities

| | | | | | |
|-----------------------------------|----------|------------|----------|--------------|-----------|
| Risk Management Commodity | | | | | |
| Contracts (a) (g) | \$ 1,451 | \$ 223,577 | \$ 5,968 | \$ (207,920) | \$ 23,076 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (a) | - | 2,784 | - | (1,371) | 1,413 |
| DETM Assignment (c) | - | - | - | 697 | 697 |
| Total Risk Management Liabilities | \$ 1,451 | \$ 226,361 | \$ 5,968 | \$ (208,594) | \$ 25,186 |

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2009

CSPCo

Level 1 Level 2 Level 3 Other Total

Assets: (in thousands)

| | | | | | |
|-------------------------|-----------|------|------|-------|-----------|
| Other Cash Deposits (d) | \$ 16,129 | \$ - | \$ - | \$ 21 | \$ 16,150 |
|-------------------------|-----------|------|------|-------|-----------|

Risk Management Assets

| | | | | | |
|------------------------------|-----------|------------|----------|--------------|-----------|
| Risk Management Commodity | | | | | |
| Contracts (a) | 1,188 | 227,150 | 6,518 | (182,038) | 52,818 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (a) | - | 1,805 | - | (821) | 984 |
| Dedesignated Risk Management | | | | | |
| Contracts (b) | - | - | - | 4,423 | 4,423 |
| Total Risk Management Assets | 1,188 | 228,955 | 6,518 | (178,436) | 58,225 |
| Total Assets | \$ 17,317 | \$ 228,955 | \$ 6,518 | \$ (178,415) | \$ 74,375 |

Liabilities:

Risk Management Liabilities

| | | | | | |
|-----------------------------------|----|-------|-------|---------|---------------------------------|
| Risk Management Commodity | | | | | |
| Contracts (a) | \$ | 1,342 | \$ | 213,330 | \$ 1,742 \$ (196,226) \$ 20,188 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (a) | | - | 2,615 | - | (821) 1,794 |
| DETM Assignment (c) | | - | - | - | 1,383 1,383 |
| Total Risk Management Liabilities | \$ | 1,342 | \$ | 215,945 | \$ 1,742 \$ (195,664) \$ 23,365 |

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2010

| I&M | Level 1 | Level 2 | Level 3 | Other | Total |
|---|------------|--------------|-----------|--------------|--------------|
| Assets: | | | | | |
| (in thousands) | | | | | |
| Risk Management Assets | | | | | |
| Risk Management Commodity Contracts (a) (g) | \$ 1,388 | \$ 247,678 | \$ 12,225 | \$ (195,907) | \$ 65,384 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (a) | - | 1,576 | - | (1,387) | 189 |
| Dedesignated Risk Management Contracts (b) | | | | | |
| | - | - | - | 3,407 | 3,407 |
| Total Risk Management Assets | 1,388 | 249,254 | 12,225 | (193,887) | 68,980 |
| Spent Nuclear Fuel and Decommissioning Trusts | | | | | |
| Cash and Cash Equivalents (e) | - | 14,009 | - | 12,503 | 26,512 |
| Fixed Income Securities: | | | | | |
| United States Government | - | 472,709 | - | - | 472,709 |
| Corporate Debt | - | 60,607 | - | - | 60,607 |
| State and Local Government | - | 316,046 | - | - | 316,046 |
| Subtotal Fixed Income Securities | - | 849,362 | - | - | 849,362 |
| Equity Securities - Domestic (f) | 515,554 | - | - | - | 515,554 |
| Total Spent Nuclear Fuel and Decommissioning Trusts | 515,554 | 863,371 | - | 12,503 | 1,391,428 |
| Total Assets | \$ 516,942 | \$ 1,112,625 | \$ 12,225 | \$ (181,384) | \$ 1,460,408 |
| Liabilities: | | | | | |
| Risk Management Liabilities | | | | | |
| Risk Management Commodity Contracts (a) (g) | \$ 1,464 | \$ 224,254 | \$ 6,016 | \$ (208,509) | \$ 23,225 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (a) | - | 2,816 | - | (1,387) | 1,429 |
| DETM Assignment (c) | - | - | - | 703 | 703 |
| Total Risk Management Liabilities | \$ 1,464 | \$ 227,070 | \$ 6,016 | \$ (209,193) | \$ 25,357 |

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2009

| I&M | Level 1 | Level 2 | Level 3 | Other | Total |
|---|----------------|--------------|----------|--------------|--------------|
| Assets: | (in thousands) | | | | |
| Risk Management Assets | | | | | |
| Risk Management Commodity Contracts (a) | \$ 1,198 | \$ 231,777 | \$ 6,571 | \$ (181,446) | \$ 58,100 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (a) | - | 1,839 | - | (828) | 1,011 |
| Dedesignated Risk Management Contracts (b) | - | - | - | 4,461 | 4,461 |
| Total Risk Management Assets | 1,198 | 233,616 | 6,571 | (177,813) | 63,572 |
| Spent Nuclear Fuel and Decommissioning Trusts | | | | | |
| Cash and Cash Equivalents (e) | - | 3,562 | - | 10,850 | 14,412 |
| Fixed Income Securities: | | | | | |
| United States Government | - | 400,565 | - | - | 400,565 |
| Corporate Debt | - | 57,291 | - | - | 57,291 |
| State and Local Government | - | 368,930 | - | - | 368,930 |
| Subtotal Fixed Income Securities | - | 826,786 | - | - | 826,786 |
| Equity Securities - Domestic (f) | 550,721 | - | - | - | 550,721 |
| Total Spent Nuclear Fuel and Decommissioning Trusts | 550,721 | 830,348 | - | 10,850 | 1,391,919 |
| Total Assets | \$ 551,919 | \$ 1,063,964 | \$ 6,571 | \$ (166,963) | \$ 1,455,491 |
| Liabilities: | | | | | |
| Risk Management Liabilities | | | | | |
| Risk Management Commodity Contracts (a) | \$ 1,353 | \$ 213,242 | \$ 1,755 | \$ (195,732) | \$ 20,618 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (a) | - | 2,637 | - | (828) | 1,809 |
| DETM Assignment (c) | - | - | - | 1,395 | 1,395 |
| Total Risk Management Liabilities | \$ 1,353 | \$ 215,879 | \$ 1,755 | \$ (195,165) | \$ 23,822 |

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2010

| OPCo | Level 1 | Level 2 | Level 3 | Other | Total |
|---|----------|------------|-----------|--------------|-----------|
| Assets: (in thousands) | | | | | |
| Risk Management Assets | | | | | |
| Risk Management Commodity Contracts (a) (g) | \$ 1,583 | \$ 332,024 | \$ 14,006 | \$ (280,140) | \$ 67,473 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (a) | - | 1,814 | - | (1,598) | 216 |
| Dedesignated Risk Management Contracts (b) | | | | | |
| | - | - | - | 3,888 | 3,888 |
| Total Risk Management Assets | \$ 1,583 | \$ 333,838 | \$ 14,006 | \$ (277,850) | \$ 71,577 |
| Liabilities: | | | | | |
| Risk Management Liabilities | | | | | |
| Risk Management Commodity Contracts (a) (g) | \$ 1,670 | \$ 317,217 | \$ 6,937 | \$ (294,903) | \$ 30,921 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (a) | - | 3,247 | - | (1,598) | 1,649 |
| DETM Assignment (c) | - | - | - | 803 | 803 |
| Total Risk Management Liabilities | \$ 1,670 | \$ 320,464 | \$ 6,937 | \$ (295,698) | \$ 33,373 |

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2009

| OPCo | Level 1 | Level 2 | Level 3 | Other | Total |
|--|----------|------------|----------|--------------|-----------|
| Assets: (in thousands) | | | | | |
| Other Cash Deposits (d) | \$ 1,075 | \$ - | \$ - | \$ 24 | \$ 1,099 |
| Risk Management Assets | | | | | |
| Risk Management Commodity Contracts (a) | 1,383 | 332,904 | 7,644 | (270,272) | 71,659 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (a) | - | 2,199 | - | (957) | 1,242 |
| Dedesignated Risk Management Contracts (b) | | | | | |
| | - | - | - | 5,150 | 5,150 |
| Total Risk Management Assets | 1,383 | 335,103 | 7,644 | (266,079) | 78,051 |
| Total Assets | \$ 2,458 | \$ 335,103 | \$ 7,644 | \$ (266,055) | \$ 79,150 |
| Liabilities: | | | | | |
| Risk Management Liabilities | | | | | |

| | | | | | |
|-----------------------------------|----|-------|----|---------|---------------------------------|
| Risk Management Commodity | | | | | |
| Contracts (a) | \$ | 1,562 | \$ | 317,114 | \$ 2,075 \$ (287,549) \$ 33,202 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (a) | | - | | 3,045 | - (957) 2,088 |
| DETM Assignment (c) | | - | | - | - 1,611 1,611 |
| Total Risk Management Liabilities | \$ | 1,562 | \$ | 320,159 | \$ 2,075 \$ (286,895) \$ 36,901 |

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2010

| PSO | Level 1 | Level 2 | Level 3 | Other | Total |
|-------------------------------------|---------|-----------|----------------|------------|----------|
| Assets: | | | (in thousands) | | |
| Risk Management Assets | | | | | |
| Risk Management Commodity Contracts | | | | | |
| (a) (g) | \$ 7 | \$ 11,959 | \$ 26 | \$ (9,359) | \$ 2,633 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (a) | - | 59 | - | (51) | 8 |
| Total Risk Management Assets | \$ 7 | \$ 12,018 | \$ 26 | \$ (9,410) | \$ 2,641 |
| Liabilities: | | | | | |
| Risk Management Liabilities | | | | | |
| Risk Management Commodity Contracts | | | | | |
| (a) (g) | \$ 11 | \$ 9,771 | \$ 28 | \$ (9,478) | \$ 332 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (a) | - | 191 | - | (51) | 140 |
| DETM Assignment (c) | - | - | - | 27 | 27 |
| Total Risk Management Liabilities | \$ 11 | \$ 9,962 | \$ 28 | \$ (9,502) | \$ 499 |

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2009

| PSO | Level 1 | Level 2 | Level 3 | Other | Total |
|-------------------------------------|---------|-----------|----------------|-------------|----------|
| Assets: | | | (in thousands) | | |
| Risk Management Assets | | | | | |
| Risk Management Commodity Contracts | | | | | |
| (a) | \$ - | \$ 17,494 | \$ 14 | \$ (15,260) | \$ 2,248 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (a) | - | 179 | - | (1) | 178 |
| Total Risk Management Assets | \$ - | \$ 17,673 | \$ 14 | \$ (15,261) | \$ 2,426 |
| Liabilities: | | | | | |
| Risk Management Liabilities | | | | | |
| Risk Management Commodity Contracts | | | | | |
| (a) | \$ - | \$ 17,865 | \$ 12 | \$ (15,454) | \$ 2,423 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (a) | - | 301 | - | (1) | 300 |
| Total Risk Management Liabilities | \$ - | \$ 18,166 | \$ 12 | \$ (15,455) | \$ 2,723 |

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Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2010

SWEPCo

| | Level 1 | Level 2 | Level 3 | Other | Total |
|---|----------------|-----------|---------|-------------|----------|
| Assets: | (in thousands) | | | | |
| Risk Management Assets | | | | | |
| Risk Management Commodity Contracts (a) (g) | \$ 8 | \$ 18,303 | \$ 36 | \$ (16,101) | \$ 2,246 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (a) | - | 47 | - | (47) | - |
| Interest Rate/Foreign | | | | | |
| Currency Hedges (a) | - | 2 | - | (2) | - |
| Total Risk Management Assets | \$ 8 | \$ 18,352 | \$ 36 | \$ (16,150) | \$ 2,246 |
| Liabilities: | | | | | |
| Risk Management Liabilities | | | | | |
| Risk Management Commodity Contracts (a) (g) | \$ 12 | \$ 17,197 | \$ 38 | \$ (16,259) | \$ 988 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (a) | - | 103 | - | (47) | 56 |
| Interest Rate/Foreign | | | | | |
| Currency Hedges (a) | - | 233 | - | (2) | 231 |
| DETM Assignment (c) | - | - | - | 32 | 32 |
| Total Risk Management Liabilities | \$ 12 | \$ 17,533 | \$ 38 | \$ (16,276) | \$ 1,307 |

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2009

SWEPCo

| | Level 1 | Level 2 | Level 3 | Other | Total |
|---|----------------|-----------|---------|-------------|----------|
| Assets: | (in thousands) | | | | |
| Risk Management Assets | | | | | |
| Risk Management Commodity Contracts (a) | \$ - | \$ 26,945 | \$ 22 | \$ (24,007) | \$ 2,960 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (a) | - | 216 | - | (43) | 173 |
| Total Risk Management Assets | \$ - | \$ 27,161 | \$ 22 | \$ (24,050) | \$ 3,133 |
| Liabilities: | | | | | |
| Risk Management Liabilities | | | | | |
| Risk Management Commodity Contracts (a) | \$ - | \$ 25,312 | \$ 19 | \$ (24,312) | \$ 1,019 |
| Cash Flow Hedges: | | | | | |
| Commodity Hedges (a) | - | 89 | - | (43) | 46 |

| | | | | | | | | | | |
|-----------------------------------|----|---|----|--------|----|----|----|----------|----|-------|
| Total Risk Management Liabilities | \$ | - | \$ | 25,401 | \$ | 19 | \$ | (24,355) | \$ | 1,065 |
|-----------------------------------|----|---|----|--------|----|----|----|----------|----|-------|

- (a) Amounts in “Other” column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for “Derivatives and Hedging.”
- (b) Represents contracts that were originally MTM but were subsequently elected as normal under the accounting guidance for “Derivatives and Hedging.” At the time of the normal election, the MTM value was frozen and no longer fair valued. This MTM value will be amortized into revenues over the remaining life of the contracts.
- (c) See “Natural Gas Contracts with DETM” section of Note 15 in the 2009 Annual Report.
- (d) Amounts in “Other” column primarily represent cash deposits with third parties. Level 1 amounts primarily represent investments in money market funds.
- (e) Amounts in “Other” column primarily represent accrued interest receivables from financial institutions. Level 2 amounts primarily represent investments in money market funds.
- (f) Amounts represent publicly traded equity securities and equity-based mutual funds.
- (g) Substantially comprised of power contracts for APCo, CSPCo, I&M and OPCo and coal contracts for PSO and SWEPCo.

There have been no transfers between Level 1 and Level 2 during the six months ended June 30, 2010.

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The following tables set forth a reconciliation of changes in the fair value of net trading derivatives classified as Level 3 in the fair value hierarchy:

| Three Months Ended June 30, 2010 | APCo | CSPCo | I&M (in thousands) | OPCo | PSO | SWEPCo |
|---|-----------|-----------|-----------------------|-----------|--------|--------|
| Balance as of March 31, 2010 | \$ 18,687 | \$ 10,570 | \$ 10,662 | \$ 12,180 | \$ 2 | \$ 4 |
| Realized Gain (Loss) Included in Net Income | | | | | | |
| (or Changes in Net Assets) | | | | | | |
| (a) (b) | (8,409) | (4,753) | (4,794) | (5,471) | (1) | (1) |
| Unrealized Gain (Loss) Included in Net | | | | | | |
| Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a) | - | (556) | - | (667) | - | - |
| Realized and Unrealized Gains (Losses) | | | | | | |
| Included in Other Comprehensive Income | - | - | - | - | - | - |
| Purchases, Issuances and Settlements (c) | 4,845 | 2,741 | 2,764 | 3,154 | (4) | (5) |
| Transfers into Level 3 (d) (h) | 1,332 | 753 | 760 | 867 | - | - |
| Transfers out of Level 3 (e) (h) | (2,006) | (1,135) | (1,145) | (1,306) | - | - |
| Changes in Fair Value Allocated to Regulated Jurisdictions (g) | (3,575) | (1,467) | (2,038) | (1,688) | 1 | - |
| Balance as of June 30, 2010 | \$ 10,874 | \$ 6,153 | \$ 6,209 | \$ 7,069 | \$ (2) | \$ (2) |
| Six Months Ended June 30, 2010 | APCo | CSPCo | I&M (in thousands) | OPCo | PSO | SWEPCo |
| Balance as of December 31, 2009 | \$ 9,428 | \$ 4,776 | \$ 4,816 | \$ 5,569 | \$ 2 | \$ 3 |
| Realized Gain (Loss) Included in Net Income | | | | | | |
| (or Changes in Net Assets) | | | | | | |
| (a) (b) | 1,232 | 693 | 698 | 797 | 7 | 9 |
| Unrealized Gain (Loss) Included in Net | | | | | | |
| Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a) | - | 5,157 | - | 5,849 | - | - |
| Realized and Unrealized Gains (Losses) | | | | | | |
| Included in Other Comprehensive Income | - | - | - | - | - | - |
| Purchases, Issuances and Settlements (c) | (4,173) | (2,321) | (2,341) | (2,675) | (6) | (7) |
| Transfers into Level 3 (d) (h) | 603 | 315 | 318 | 366 | - | - |
| Transfers out of Level 3 (e) (h) | (1,738) | (999) | (1,008) | (1,148) | - | - |

Changes in Fair Value Allocated to
Regulated

| Jurisdictions (g) | 5,522 | (1,468) | 3,726 | (1,689) | (5) | (7) |
|-----------------------------|-----------|----------|----------|----------|--------|--------|
| Balance as of June 30, 2010 | \$ 10,874 | \$ 6,153 | \$ 6,209 | \$ 7,069 | \$ (2) | \$ (2) |

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| Three Months Ended June 30, 2009 | APCo | CSPCo | I&M (in thousands) | OPCo | PSO | SWEPCo |
|--|-----------|----------|-----------------------|----------|--------|--------|
| Balance as of March 31, 2009 | \$ 11,847 | \$ 6,294 | \$ 6,092 | \$ 7,802 | \$ 1 | \$ 2 |
| Realized (Gain) Loss Included in Net Income | | | | | | |
| (or Changes in Net Assets) | | | | | | |
| (a) | (4,739) | (2,514) | (2,432) | (3,103) | 3 | 5 |
| Unrealized Gain (Loss) Included in Net | | | | | | |
| Income (or Changes in Net Assets) Relating | | | | | | |
| to Assets Still Held at the Reporting Date (a) | - | 3,878 | - | 5,065 | - | - |
| Realized and Unrealized Gains (Losses) | | | | | | |
| Included in Other Comprehensive Income | - | - | - | - | - | - |
| Purchases, Issuances and Settlements | - | - | - | - | - | - |
| Transfers in and/or out of Level 3 (f) | (2,419) | (1,283) | (1,241) | (1,589) | - | - |
| Changes in Fair Value Allocated to Regulated | | | | | | |
| Jurisdictions (g) | 9,211 | 997 | 4,716 | 1,235 | 8 | 8 |
| Balance as of June 30, 2009 | \$ 13,900 | \$ 7,372 | \$ 7,135 | \$ 9,410 | \$ 12 | \$ 15 |
| Six Months Ended June 30, 2009 | APCo | CSPCo | I&M (in thousands) | OPCo | PSO | SWEPCo |
| Balance as of December 31, 2008 | \$ 8,009 | \$ 4,497 | \$ 4,352 | \$ 5,563 | \$ (2) | \$ (3) |
| Realized (Gain) Loss Included in Net Income | | | | | | |
| (or Changes in Net Assets) | | | | | | |
| (a) | (6,200) | (3,482) | (3,369) | (4,301) | 3 | 5 |
| Unrealized Gain (Loss) Included in Net | | | | | | |
| Income (or Changes in Net Assets) Relating | | | | | | |
| to Assets Still Held at the Reporting Date (a) | - | 5,466 | - | 6,907 | - | - |
| Realized and Unrealized Gains (Losses) | | | | | | |
| Included in Other Comprehensive Income | - | - | - | - | - | - |
| Purchases, Issuances and Settlements | - | - | - | - | - | - |
| Transfers in and/or out of Level 3 (f) | (176) | (106) | (97) | 6 | 36 | 58 |
| Changes in Fair Value Allocated to Regulated | | | | | | |
| Jurisdictions (g) | 12,267 | 997 | 6,249 | 1,235 | (25) | (45) |
| Balance as of June 30, 2009 | \$ 13,900 | \$ 7,372 | \$ 7,135 | \$ 9,410 | \$ 12 | \$ 15 |

(a) Included in revenues on the Condensed Statements of Income.

- (b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
- (c) Represents the settlement of risk management commodity contracts for the reporting period.
- (d) Represents existing assets or liabilities that were previously categorized as Level 2.
- (e) Represents existing assets or liabilities that were previously categorized as Level 3.
- (f) Represents existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during the period.
- (g) Relates to the net gains (losses) of those contracts that are not reflected on the Condensed Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities.
- (h) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.

10. **INCOME TAXES**

The Registrant Subsidiaries join in the filing of a consolidated federal income tax return with their affiliates in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The tax benefit of the Parent is allocated to its subsidiaries with taxable income. With the exception of the loss of the Parent, the method of allocation reflects a separate return result for each company in the consolidated group.

The Registrant Subsidiaries are no longer subject to U.S. federal examination for years before 2001. The Registrant Subsidiaries have completed the exam for the years 2001 through 2006 and have issues that are being pursued at the appeals level. The years 2007 and 2008 are currently under examination. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. In addition, the Registrant Subsidiaries accrue interest on these uncertain tax positions.

Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on net income.

The Registrant Subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine their tax returns and the Registrant Subsidiaries are currently under examination in several state and local jurisdictions. Management believes that previously filed tax returns have positions that may be challenged by these tax authorities. However, management believes that the ultimate resolution of these audits will not materially impact net income. With few exceptions, the Registrant Subsidiaries are no longer subject to state or local income tax examinations by tax authorities for years before 2000.

Federal Legislation – Affecting APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

The Patient Protection and Affordable Care Act and the related Health Care and Education Reconciliation Act (Health Care Acts) were enacted in March 2010. The Health Care Acts amend tax rules so that the portion of employer health care costs that are reimbursed by the Medicare Part D prescription drug subsidy will no longer be deductible by the employer for federal income tax purposes effective for years beginning after December 31, 2012. Because of the loss of the future tax deduction, a reduction in the deferred tax asset related to the nondeductible OPEB liabilities accrued to date was recorded by the Registrant Subsidiaries in March 2010. This reduction did not materially affect the Registrant Subsidiaries' cash flows or financial condition. For the six months ended June 30, 2010, the Registrant Subsidiaries reflected a decrease in deferred tax assets, which was partially offset by recording net tax regulatory assets in jurisdictions with regulated operations, resulting in a decrease in net income as follows:

| Company | Net Reduction to Deferred Tax Assets | Tax Regulatory Assets, Net (in thousands) | Decrease in Net Income |
|---------|--|--|---------------------------|
| APCo | \$ 9,397 | \$ 8,831 | \$ 566 |
| CSPCo | 4,386 | 2,970 | 1,416 |
| I&M | 7,212 | 6,528 | 684 |
| OPCo | 8,385 | 4,020 | 4,365 |
| PSO | 3,172 | 3,172 | - |
| SWEPCo | 3,412 | 3,412 | - |

11. FINANCING ACTIVITIES

Long-term Debt

Long-term debt and other securities issued, retired and principal payments made during the first six months of 2010 were:

| Company | Type of Debt | Principal Amount (in thousands) | Interest Rate (%) | Due Date |
|------------|-------------------------|--|-------------------------|-------------|
| Issuances: | | | | |
| APCo | Senior Unsecured Notes | \$ 300,000 | 3.40 | 2015 |
| APCo | Pollution Control Bonds | 17,500 | 4.625 | 2021 |
| APCo | Pollution Control Bonds | 50,000 | 5.375 | 2038 |
| CSPCo | Floating Rate Notes | 150,000 | Variable | 2012 |
| I&M | Notes Payable | 84,500 | 4.00 | 2014 |

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| | | | | |
|--------|-------------------------|---------|-------|------|
| OPCo | Pollution Control Bonds | 79,450 | 3.25 | 2014 |
| OPCo | Pollution Control Bonds | 86,000 | 3.125 | 2015 |
| SWEPCo | Senior Unsecured Notes | 350,000 | 6.20 | 2040 |
| SWEPCo | Pollution Control Bonds | 53,500 | 3.25 | 2015 |

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| Company | Type of Debt | Principal Amount Paid (in thousands) | Interest Rate (%) | Due Date |
|-------------------------------------|----------------------------|--------------------------------------|-------------------|----------|
| Retirements and Principal Payments: | | | | |
| APCo | Land Note | \$ 9 | 13.718 | 2026 |
| APCo | Notes Payable - Affiliated | 100,000 | 4.708 | 2010 |
| APCo | Senior Unsecured Notes | 150,000 | 4.40 | 2010 |
| APCo | Pollution Control Bonds | 50,000 | 7.125 | 2010 |
| CSPCo | Notes Payable - Affiliated | 100,000 | 4.64 | 2010 |
| I&M | Notes Payable - Affiliated | 25,000 | 5.375 | 2010 |
| I&M | Notes Payable | 19,200 | 5.44 | 2013 |
| OPCo | Senior Unsecured Notes | 400,000 | Variable | 2010 |
| OPCo | Pollution Control Bonds | 79,450 | 7.125 | 2010 |
| SWEPCo | Notes Payable - Affiliated | 50,000 | 4.45 | 2010 |
| SWEPCo | Pollution Control Bonds | 53,500 | Variable | 2019 |

On behalf of OPCo, trustees held \$303 million of reacquired auction-rate tax-exempt long-term debt as of June 30, 2010.

Dividend Restrictions

The Registrant Subsidiaries pay dividends to the Parent provided funds are legally available. Various financing arrangements, charter provisions and regulatory requirements may impose certain restrictions on the ability of the Registrant Subsidiaries to transfer funds to the Parent in the form of dividends.

Federal Power Act

The Federal Power Act prohibits each of the Registrant Subsidiaries from participating “in the making or paying of any dividends of such public utility from any funds properly included in capital account.” The term “capital account” is not defined in the Federal Power Act or its regulations. As applicable, the Registrant Subsidiaries understand “capital account” to mean the par value of the common stock multiplied by the number of shares outstanding.

Additionally, the Federal Power Act creates a reserve on earnings attributable to hydroelectric generating plants. Because of their respective ownership of such plants, this reserve applies to APCo, I&M and OPCo.

None of these restrictions limit the ability of the Registrant Subsidiaries to pay dividends out of retained earnings.

Charter and Leverage Restrictions

Provisions within the articles or certificates of incorporation of the Registrant Subsidiaries relating to preferred stock or shares restrict the payment of cash dividends on common and preferred stock or shares. Pursuant to the credit agreement leverage restrictions, the Registrant Subsidiaries must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. The payment of cash dividends generally results in an increase in the percentage of debt to total capitalization of the company distributing the dividend. The method for calculating outstanding debt and other capital is contractually defined in the credit agreements. As of June 30, 2010, approximately \$204 million of the retained earnings of APCo, \$149 million of the retained earnings of CSPCo, \$33

million of the retained earnings of I&M, \$50 million of the retained earnings of OPCo, \$101 million of the retained earnings of SWEPCo and none of the retained earnings of PSO have restrictions related to the payment of dividends to Parent.

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding loans (borrowings) to/from the Utility Money Pool as of June 30, 2010 and December 31, 2009 is included in Advances to/from Affiliates on each of the Registrant Subsidiaries' balance sheets. The Utility Money Pool participants' money pool activity and their corresponding authorized borrowing limits for the six months ended June 30, 2010 are described in the following table:

| Company | Maximum Borrowings from Utility Money Pool | Maximum Loans to Utility Money Pool | Average Borrowings from Utility Money Pool (in thousands) | Average Loans to Utility Money Pool | Loans to (Borrowings) to/from Utility Money Pool as of June 30, 2010 | Authorized Short-term Borrowing Limit |
|---------|--|-------------------------------------|---|-------------------------------------|--|---------------------------------------|
| APCo | \$ 438,039 | \$ - | \$ 290,958 | \$ - | \$ (246,873) | \$ 600,000 |
| CSPCo | 134,592 | 70,826 | 32,368 | 29,474 | 57,069 | 350,000 |
| I&M | - | 165,687 | - | 96,954 | 126,515 | 500,000 |
| OPCo | - | 618,559 | - | 320,872 | 172,751 | 600,000 |
| PSO | 107,320 | 74,751 | 56,695 | 51,041 | (66,229) | 300,000 |
| SWEPCo | 78,616 | 274,958 | 39,458 | 208,666 | 245,253 | 350,000 |

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool were as follows:

| | Six Months Ended June 30, | | | |
|-----------------------|---------------------------|---|------|---|
| | 2010 | | 2009 | |
| Maximum Interest Rate | 0.51 | % | 2.28 | % |
| Minimum Interest Rate | 0.09 | % | 0.65 | % |

The average interest rates for funds borrowed from and loaned to the Utility Money Pool for the six months ended June 30, 2010 and 2009 are summarized for all Registrant Subsidiaries in the following table:

| Company | Average Interest Rate for Funds Borrowed from the Utility Money Pool for the Six Months Ended June 30, | | | | Average Interest Rate for Funds Loaned to the Utility Money Pool for the Six Months Ended June 30, | | | |
|---------|--|---|------|---|--|---|------|---|
| | 2010 | | 2009 | | 2010 | | 2009 | |
| APCo | 0.23 | % | 1.45 | % | - | % | - | % |
| CSPCo | 0.18 | % | 1.27 | % | 0.26 | % | - | % |
| I&M | - | % | 1.47 | % | 0.21 | % | 1.71 | % |
| OPCo | - | % | 1.35 | % | 0.18 | % | 0.72 | % |
| PSO | 0.28 | % | 2.01 | % | 0.16 | % | 1.31 | % |
| SWEPCo | 0.19 | % | 1.67 | % | 0.25 | % | 1.38 | % |

To meet its short-term borrowing needs, DHLC is also a member of the Utility Money Pool. Effective January 1, 2010, SWEPCo no longer consolidates DHLC. DHLC's money pool activity for the six months ended June 30, 2010

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is described in the following table:

| Maximum Borrowings from Utility Money Pool | Maximum Loans to Utility Money Pool | Average Borrowings from Utility Money Pool (in thousands) | Average Loans to Utility Money Pool | Borrowings from Utility Money Pool as of June 30, 2010 |
|---|--|---|--|--|
| \$ 23,145 | \$ - | \$ 14,791 | \$ - | \$ 19,962 |

DHLC's maximum, minimum and average interest rates for funds borrowed from and loaned to the Utility Money Pool for the six months ended June 30, 2010 were as follows:

| | Maximum Interest Rates for Funds | Minimum Interest Rates for Funds | Maximum Interest Rates for Funds | Minimum Interest Rates for Funds | Average Interest Rates for Funds | Average Interest Rates for Funds |
|---|--|--|--|--|--|--|
| Six Months Ended June 30, 2010 | Borrowed from the Utility Money Pool | Borrowed from the Utility Money Pool | Loaned to the Utility Money Pool | Loaned to the Utility Money Pool | Borrowed from the Utility Money Pool | Loaned to the Utility Money Pool |
| | 0.51 % | 0.09 % | - % | - % | 0.24 % | - % |

Short-term Debt

The Registrant Subsidiaries' outstanding short-term debt was as follows:

| Company | Type of Debt | June 30, 2010 | | December 31, 2009 | |
|---------|-------------------------------|---|----------------------|---|----------------------|
| | | Outstanding Amount (in thousands) | Interest Rate (b) | Outstanding Amount (in thousands) | Interest Rate (b) |
| SWEP | CoLine of Credit – Sabine (a) | \$ 8,717 | 2.11 % | \$ 6,890 | 2.06 % |

(a) Sabine Mining Company is a consolidated variable interest entity.

(b) Weighted average rate.

Credit Facilities

AEP has credit facilities totaling \$3 billion to support the commercial paper program. The facilities are structured as two \$1.5 billion credit facilities, of which \$750 million may be issued under one credit facility as letters of credit. In June 2010, AEP canceled a facility that was scheduled to mature in March 2011 and entered into a new \$1.5 billion credit facility scheduled to mature in 2013 that allows for the issuance of up to \$600 million as letters of credit. As of June 30, 2010, the maximum future payments for letters of credit issued under the two \$1.5 billion credit facilities were \$300 thousand for I&M and \$4 million for SWEPCo.

In June 2010, the Registrant Subsidiaries and certain other companies in the AEP System reduced the \$627 million credit agreement to \$478 million. Under the facility, letters of credit may be issued. As of June 30, 2010, \$477 million of letters of credit were issued to support variable rate Pollution Control Bonds as follows:

| Company | Amount (in thousands) |
|---------|--------------------------|
| APCo | \$ 232,292 |
| I&M | 77,886 |
| OPCo | 166,899 |

Sale of Receivables – AEP Credit

Under a sale of receivables arrangement, the Registrant Subsidiaries sell, without recourse, certain of their customer accounts receivable and accrued unbilled revenue balances to AEP Credit and are charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for each Registrant Subsidiaries' receivables. APCo does not have regulatory authority to sell its West Virginia accounts receivable. The costs of customer accounts receivable sold are reported in Other Operation on the Registrant Subsidiaries' income

statements. The Registrant Subsidiaries manage and service their customer accounts receivable sold.

In July 2010, AEP Credit renewed its receivables securitization agreement. The agreement provides a commitment of \$750 million from bank conduits to purchase receivables. A commitment of \$375 million expires in July 2011 and the remaining commitment of \$375 million expires in July 2013.

The amount of accounts receivable and accrued unbilled revenues under the sale of receivables agreement for each Registrant Subsidiary as of June 30, 2010 and December 31, 2009 was as follows:

| Company | June 30, 2010 | December 31, 2009 |
|----------------|------------------|----------------------|
| (in thousands) | | |
| APCo | \$ 170,388 | \$ 143,938 |
| CSPCo | 192,997 | 169,095 |
| I&M | 131,292 | 130,193 |
| OPCo | 169,898 | 160,977 |
| PSO | 138,138 | 73,518 |
| SWEPCo | 154,745 | 117,297 |

The fees paid by the Registrant Subsidiaries to AEP Credit for customer accounts receivable sold were:

| Company | Three Months Ended June 30, | | Six Months Ended June 30, | |
|----------------|-----------------------------|----------|---------------------------|----------|
| | 2010 | 2009 | 2010 | 2009 |
| (in thousands) | | | | |
| APCo | \$ 1,895 | \$ 1,074 | \$ 3,776 | \$ 2,525 |
| CSPCo | 2,782 | 2,613 | 5,690 | 5,525 |
| I&M | 1,657 | 1,333 | 3,444 | 2,890 |
| OPCo | 2,449 | 1,903 | 5,149 | 4,011 |
| PSO | 1,367 | 1,711 | 2,750 | 3,659 |
| SWEPCo | 1,462 | 1,366 | 3,133 | 2,822 |

The Registrant Subsidiaries' proceeds on the sale of receivables to AEP Credit were:

| Company | Three Months Ended June 30, | | Six Months Ended June 30, | |
|----------------|-----------------------------|------------|---------------------------|------------|
| | 2010 | 2009 | 2010 | 2009 |
| (in thousands) | | | | |
| APCo | \$ 317,120 | \$ 276,070 | \$ 758,830 | \$ 624,411 |
| CSPCo | 422,628 | 404,071 | 847,313 | 801,246 |
| I&M | 297,384 | 286,176 | 636,593 | 588,075 |
| OPCo | 410,331 | 376,810 | 851,840 | 790,409 |
| PSO | 311,883 | 275,221 | 526,530 | 546,642 |
| SWEPCo | 338,286 | 325,562 | 657,245 | 635,319 |

12. COST REDUCTION INITIATIVES

In April 2010, management began initiatives to decrease both labor and non-labor expenses with a goal of achieving significant reductions in operation and maintenance expenses. A total of 2,461 positions were eliminated as a result of process improvements, streamlined organizational designs and other efficiencies. Most of the affected employees terminated employment May 31, 2010. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

Management recorded a charge to expense in the second quarter of 2010 primarily related to the headcount reduction initiatives.

| | Expense Allocation from AEPSC | Incurred for Registrant Subsidiaries | Settled | Remaining Balance at June 30, 2010 |
|--------|--|--|---------|--|
| | | (in thousands) | | |
| APCo | \$ 20,526 | \$ 36,399 | \$ 753 | \$ 56,172 |
| CSPCo | 11,048 | 21,244 | 387 | 31,905 |
| I&M | 12,051 | 32,985 | 885 | 44,151 |
| OPCo | 19,427 | 33,681 | 979 | 52,129 |
| PSO | 10,681 | 13,324 | 231 | 23,774 |
| SWEPCo | 12,588 | 17,074 | 421 | 29,241 |

These costs relate primarily to severance benefits. They are included primarily in Other Operation on the income statement and Other Current Liabilities on the balance sheet.

COMBINED MANAGEMENT'S DISCUSSION AND ANALYSIS OF REGISTRANT SUBSIDIARIES

The following is a combined presentation of certain components of the Registrant Subsidiaries' management's discussion and analysis. The information in this section completes the information necessary for management's discussion and analysis of financial condition and net income and is meant to be read with (i) Management's Financial Discussion and Analysis, (ii) financial statements, (iii) footnotes and (iv) the schedules of each individual registrant. The combined Management's Discussion and Analysis of Registrant Subsidiaries section of the 2009 Annual Report should also be read in conjunction with this report.

EXECUTIVE OVERVIEW

Economic Conditions

The Registrant Subsidiaries' retail margins increased primarily due to successful rate proceedings in Indiana, Ohio, Oklahoma and Virginia and higher residential and commercial demand for electricity as a result of favorable weather.

In comparison to the recessionary lows of 2009, industrial sales increased 9% in the second quarter and 4% during the first six months of 2010 for the AEP System. During 2009, the Registrant Subsidiaries' operations were impacted by difficult economic conditions especially their industrial sales reflecting customers' curtailments or closures of facilities. In 2009, CSPCo's and OPCo's largest customer, Ormet, a major industrial customer, currently operating at a reduced load of approximately 330 MW, (Ormet operated at an approximate 500 MW load in 2008), announced that it will continue operations at this reduced level. In February 2009, Century Aluminum, a major industrial customer (325 MW load) of APCo, announced the curtailment of operations at its Ravenswood, WV facility.

Cost Reduction Initiatives

Due to the continued slow recovery in the U.S. economy and a corresponding negative impact on energy consumption, the AEP System implemented cost reduction initiatives in the second quarter of 2010 to reduce its workforce by 11.5% and reduce other operation and maintenance spending. Achieving these goals involved identifying process improvements, streamlining organizational designs and developing other efficiencies that will deliver additional sustainable savings. In the second quarter of 2010, \$293 million of expense were recorded related to these cost reduction initiatives.

FINANCIAL CONDITION

LIQUIDITY

Sources of Funding

Short-term funding for the Registrant Subsidiaries comes from AEP's commercial paper program and revolving credit facilities through the Utility Money Pool. AEP and its Registrant Subsidiaries operate a money pool to minimize the AEP System's external short-term funding requirements and sell accounts receivable to provide liquidity. Under credit facilities, \$1.35 billion may be issued as letters of credit (LOC). The Registrant Subsidiaries generally use short-term funding sources (the Utility Money Pool or receivables sales) to provide for interim financing of capital expenditures that exceed internally generated funds and periodically reduce their outstanding short-term debt through issuances of long-term debt, sale-leasebacks, leasing arrangements and additional capital contributions from Parent.

The Registrant Subsidiaries and certain other companies in the AEP System entered into a 3-year credit agreement which matures in April 2011. In June 2010, the credit facility was reduced from \$627 million to \$478 million. The Registrant Subsidiaries may issue LOCs under the credit facility. Each subsidiary has a borrowing/LOC limit under the credit facility. As of June 30, 2010, a total of \$477 million of LOCs were issued under the credit agreement to support variable rate demand notes. The following table shows each Registrant Subsidiaries' borrowing/LOC limit under the credit facility and the outstanding amount of LOCs.

| Company | Credit Facility Borrowing/LOC Limit | LOC Amount Outstanding Against the Agreement at June 30, 2010 |
|---------|---|---|
| | (in millions) | |
| APCo | \$ 300 | \$ 232 |
| CSPCo | 230 | - |
| I&M | 230 | 78 |
| OPCo | 400 | 167 |
| PSO | 65 | - |
| SWEPCo | 230 | - |

Dividend Restrictions

Under the Federal Power Act, the Registrant Subsidiaries are restricted from paying dividends out of stated capital. Various financing arrangements, charter provisions and regulatory requirements may impose certain restrictions on the ability of the Registrant Subsidiaries to transfer funds to Parent in the form of dividends.

Sales of Receivables

In July 2010, AEP Credit renewed its receivables securitization agreement. The agreement provides a commitment of \$750 million from bank conduits to purchase receivables. A commitment of \$375 million expires in July 2011 and the remaining commitment of \$375 million expires in July 2013. AEP Credit purchases accounts receivable from the Registrant Subsidiaries.

SIGNIFICANT FACTORS

ENVIRONMENTAL ISSUES

The Registrant Subsidiaries are implementing a substantial capital investment program and incurring additional operational costs to comply with new environmental control requirements. Management anticipates making additional investments and operational changes. The most significant sources are the existing and anticipated CAA requirements to reduce emissions of SO₂, NO_x, PM and hazardous air pollutants from fossil fuel-fired power plants and new proposals governing the beneficial use and disposal of coal combustion products.

The Registrant Subsidiaries are engaged in litigation about environmental issues, have been notified of potential responsibility for the clean-up of contaminated sites and incur costs for disposal of spent nuclear fuel and future decommissioning of I&M's nuclear units. Management is also involved in development of possible future requirements to reduce CO₂ emissions to address concerns about global climate change. See a complete discussion of these matters in the "Environmental Matters" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" in the 2009 Annual Report.

Clean Air Act Transport Rule (Transport Rule)

In July 2010, the Federal EPA issued a proposed rule to replace the Clean Air Interstate Rule (CAIR) that would impose new and more stringent requirements to control SO₂ and NO_x emissions from fossil fuel-fired electric generating units in 31 states and the District of Columbia. Each state covered by the Transport Rule is assigned an allowance budget for SO₂ and/or NO_x. Limited interstate trading is allowed on a sub-regional basis and intrastate trading is allowed among generating units. PSO's and SWEPCo's western states (Texas, Arkansas and Oklahoma) would be subject to only the seasonal NO_x program, with new limits that are proposed to take effect in 2012. The

remainder of the states in which the AEP System operates would be subject to seasonal and annual NOx programs and an annual SO2 emissions reduction program that takes effect in two phases. The first phase becomes effective in 2012 and requires approximately 1 million tons per year more SO2 emission reductions across the region than would have been required under CAIR. The second phase takes effect in 2014 and reduces emissions by an additional 800,000 tons per year. The SO2 and NOx programs rely on newly-created allowances rather than relying on the CAIR NOx allowances or the Title IV Acid Rain Program allowances used in the CAIR rule. The time frames for and stringency of the additional emission reductions, coupled with the lack of robust interstate trading and the elimination of historic allowance banks, pose significant concerns for the AEP System and its electric utility customers, as these features could accelerate unit retirements, increase capital requirements, constrain operations and decrease reliability. Comments on the proposed rule will be due within 60 days after publication in the Federal Register.

Coal Combustion Residual Rule

In June 2010, the Federal EPA published a proposed rule to regulate the disposal and beneficial re-use of coal combustion residuals, including fly ash and bottom ash generated at the coal-fired electric generating units. The rule contains two alternative proposals, one that would impose federal hazardous waste disposal and management standards on these materials and one that would allow states to retain primary authority to regulate the beneficial re-use and disposal of these materials under state solid waste management standards, including minimum federal standards for disposal and management. Both proposals would impose stringent requirements for the construction of new coal ash landfills and would require existing unlined surface impoundments to upgrade to the new standards or stop receiving coal ash and initiate closure within five years of the issuance of a final rule.

Currently, approximately 40% of the coal ash and other residual products from the AEP System's generating facilities are re-used in the production of cement and wallboard, as structural fill or soil amendments, as abrasives or road treatment materials and for other beneficial uses. Certain of these uses would no longer be available and others are likely to significantly decline if coal ash and related materials are classified as hazardous wastes. In addition, surface impoundments and landfills to manage these materials are currently used at the generating facilities. The Registrant Subsidiaries will incur significant costs to upgrade or close and replace their existing facilities. Management is currently studying the potential costs associated with this proposal, but expects that it will impose significant costs that, if not recovered through regulated rates or market prices for electricity, will have a material adverse impact on net income, cash flows and financial condition.

Global Warming

While comprehensive economy-wide regulation of CO2 emissions might be achieved through new legislation, Congress has yet to enact such legislation. The Federal EPA continues to take action to regulate CO2 emissions under the existing requirements of the CAA. The Federal EPA issued a final endangerment finding for CO2 emissions from new motor vehicles in December 2009 and final rules for new motor vehicles in May 2010. The Federal EPA determined that CO2 emissions from stationary sources will be subject to regulation under the CAA beginning in January 2011 at the earliest and finalized its proposed scheme to streamline and phase-in regulation of stationary source CO2 emissions through the NSR prevention of significant deterioration and Title V operating permit programs. The Federal EPA is reconsidering whether to include CO2 emissions in a number of stationary source standards, including standards that apply to new and modified electric utility units.

The Registrant Subsidiaries' fossil fuel-fired generating units are very large sources of CO2 emissions. If substantial CO2 emission reductions are required, there will be significant increases in capital expenditures and operating costs which would impact the ultimate retirement of older, less-efficient, coal-fired units. To the extent the Registrant Subsidiaries install additional controls on their generating plants to limit CO2 emissions and receive regulatory approvals to increase rates, cost recovery could have a positive effect on future earnings. Prudently incurred capital investments made by the Registrant Subsidiaries in rate-regulated jurisdictions to comply with legal requirements and

benefit customers are generally included in rate base for recovery and earn a return on investment. Management would expect these principles to apply to investments made to address new environmental requirements. However, requests for rate increases reflecting these costs can affect the Registrant Subsidiaries adversely because the regulators could limit the amount or timing of increased costs that would be recoverable through higher rates. In addition, to the extent the Registrant Subsidiaries' costs are relatively higher than their competitors' costs, such as operators of nuclear generation, it could reduce off-system sales or cause the Registrant Subsidiaries to lose customers in jurisdictions that permit customers to choose their supplier of generation service.

Several states have adopted programs that directly regulate CO₂ emissions from power plants, but none of these programs are currently in effect in states where the Registrant Subsidiaries have generating facilities. Certain states, including Ohio, Michigan, Texas and Virginia, passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements. The Registrant Subsidiaries are taking steps to comply with these requirements.

Certain groups have filed lawsuits alleging that emissions of CO₂ are a “public nuisance” and seeking injunctive relief and/or damages from small groups of coal-fired electricity generators, petroleum refiners and marketers, coal companies and others. The Registrant Subsidiaries have been named in pending lawsuits, which management is vigorously defending. It is not possible to predict the outcome of these lawsuits or their impact on operations or financial condition. See “Carbon Dioxide Public Nuisance Claims” and “Alaskan Villages’ Claims” sections of Note 4.

Future federal and state legislation or regulations that mandate limits on the emission of CO₂ would result in significant increases in capital expenditures and operating costs, which, in turn, could lead to increased liquidity needs and higher financing costs. Excessive costs to comply with future legislation or regulations might force the Registrant Subsidiaries to close some coal-fired facilities and could lead to possible impairment of assets. As a result, mandatory limits could have a material adverse impact on net income, cash flows and financial condition.

For detailed information on global warming and the actions the AEP System is taking address potential impacts, see Part I of the 2009 Form 10-K under the headings entitled “Business – General – Environmental and Other Matters – Global Warming and “Combined Management Discussion and Analysis of Registrant Subsidiaries.”

NEW ACCOUNTING PRONOUNCEMENTS

New Accounting Pronouncement Adopted During 2010

The Registrant Subsidiaries prospectively adopted ASU 2009-17 “Consolidation” effective January 1, 2010. SWEPCo no longer consolidates DHLC effective with the adoption of this standard.

See Note 2 for further discussion of accounting pronouncements.

Future Accounting Changes

The FASB’s standard-setting process is ongoing and until new standards have been finalized and issued, management cannot determine the impact on the reporting of the Registrant Subsidiaries’ operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, contingencies, financial instruments, emission allowances, fair value measurements, leases, insurance, hedge accounting, consolidation policy and discontinued operations. Management also expects to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on future net income and financial position.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT RISK MANAGEMENT ACTIVITIES

Market Risks

The Registrant Subsidiaries’ risk management assets and liabilities are managed by AEPSC as agent. The related risk management policies and procedures are instituted and administered by AEPSC. See complete discussion within AEP’s “Quantitative and Qualitative Disclosures About Risk Management Activities” section. Also, see Note 8 – Derivatives and Hedging and Note 9 – Fair Value Measurements for additional information related to the Registrant

Subsidiaries' risk management contracts.

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The following tables summarize the reasons for changes in total mark-to-market (MTM) value as compared to December 31, 2009:

MTM Risk Management Contract Net Assets (Liabilities)
Six Months Ended June 30, 2010
(in thousands)

APCo

| | | |
|---|----|----------|
| Total MTM Risk Management Contract Net Assets at December 31, 2009 | \$ | 45,197 |
| (Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period | | (13,316) |
| Fair Value of New Contracts at Inception When Entered During the Period (a) | | - |
| Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered | | |
| During the Period | | (214) |
| Changes in Fair Value Due to Market Fluctuations During the Period (c) | | (23) |
| Changes in Fair Value Allocated to Regulated Jurisdictions (d) | | 7,981 |
| Total MTM Risk Management Contract Net Assets | | 39,625 |
| Cash Flow Hedge Contracts | | (2,185) |
| DETM Assignment (e) | | (1,233) |
| Collateral Deposits | | 22,117 |
| Total MTM Derivative Contract Net Assets at June 30, 2010 | \$ | 58,324 |

OPCo

| | | |
|---|----|---------|
| Total MTM Risk Management Contract Net Assets at December 31, 2009 | \$ | 26,330 |
| (Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period | | (8,420) |
| Fair Value of New Contracts at Inception When Entered During the Period (a) | | 4,722 |
| Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts (b) | | (715) |
| Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered | | |
| During the Period | | (418) |
| Changes in Fair Value Due to Market Fluctuations During the Period (c) | | 5,843 |
| Changes in Fair Value Allocated to Regulated Jurisdictions (d) | | (1,665) |
| Total MTM Risk Management Contract Net Assets | | 25,677 |
| Cash Flow Hedge Contracts | | (1,433) |
| DETM Assignment (e) | | (803) |
| Collateral Deposits | | 14,763 |
| Total MTM Derivative Contract Net Assets at June 30, 2010 | \$ | 38,204 |

| | |
|---|----------|
| PSO | |
| Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2009 | \$ (369) |
| (Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period | 100 |
| Fair Value of New Contracts at Inception When Entered During the Period (a) | - |
| Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered | |
| During the Period | (48) |
| Changes in Fair Value Due to Market Fluctuations During the Period (c) | (1) |
| Changes in Fair Value Allocated to Regulated Jurisdictions (d) | 2,500 |
| Total MTM Risk Management Contract Net Assets | 2,182 |
| Cash Flow Hedge Contracts | (132) |
| DETM Assignment (e) | (27) |
| Collateral Deposits | 119 |
| Total MTM Derivative Contract Net Assets at June 30, 2010 | \$ 2,142 |
| SWEPCo | |
| Total MTM Risk Management Contract Net Assets at December 31, 2009 | \$ 1,636 |
| (Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period | (1,115) |
| Fair Value of New Contracts at Inception When Entered During the Period (a) | - |
| Net Option Premiums Paid/(Received) for Unexercised or Unexpired Option Contracts Entered | |
| During the Period | (84) |
| Changes in Fair Value Due to Market Fluctuations During the Period (c) | (2) |
| Changes in Fair Value Allocated to Regulated Jurisdictions (d) | 665 |
| Total MTM Risk Management Contract Net Assets | 1,100 |
| Cash Flow Hedge Contracts | (287) |
| DETM Assignment (e) | (32) |
| Collateral Deposits | 158 |
| Total MTM Derivative Contract Net Assets at June 30, 2010 | \$ 939 |

- (a) Reflects fair value on long-term contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.
- (b) Reflects changes in methodology in calculating the credit and discounting liability fair value adjustments.
- (c) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
- (d) Relates to the net gains (losses) of those contracts that are not reflected on the Condensed Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets.
- (e) See "Natural Gas Contracts with DETM" section of Note 15 of the 2009 Annual Report.

The following tables present the maturity, by year, of net assets/liabilities to give an indication of when these MTM amounts will settle and generate or (require) cash:

Maturity and Source of Fair Value of MTM
Risk Management Contract Net Assets (Liabilities)
June 30, 2010
(in thousands)

| | Remainder | | | |
|------------------------------|-----------|-----------|----------|-----------|
| APCo | 2010 | 2011-2013 | 2014+ | Total |
| Level 1 (a) | \$ (170) | \$ 37 | \$ - | \$ (133) |
| Level 2 (b) | 10,304 | 11,565 | 1,043 | 22,912 |
| Level 3 (c) | 3,851 | 4,986 | 2,037 | 10,874 |
| Total | 13,985 | 16,588 | 3,080 | 33,653 |
| Dedesignated Risk Management | | | | |
| Contracts (d) | 2,495 | 3,477 | - | 5,972 |
| Total MTM Risk Management | | | | |
| Contract Net Assets | \$ 16,480 | \$ 20,065 | \$ 3,080 | \$ 39,625 |

| | Remainder | | | |
|------------------------------|-----------|-----------|----------|-----------|
| OPCo | 2010 | 2011-2013 | 2014+ | Total |
| Level 1 (a) | \$ (111) | \$ 24 | \$ - | \$ (87) |
| Level 2 (b) | 7,682 | 6,446 | 679 | 14,807 |
| Level 3 (c) | 2,496 | 3,247 | 1,326 | 7,069 |
| Total | 10,067 | 9,717 | 2,005 | 21,789 |
| Dedesignated Risk Management | | | | |
| Contracts (d) | 1,624 | 2,264 | - | 3,888 |
| Total MTM Risk Management | | | | |
| Contract Net Assets | \$ 11,691 | \$ 11,981 | \$ 2,005 | \$ 25,677 |

| | Remainder | | | |
|-----------------------------------|-----------|-----------|--|----------|
| PSO | 2010 | 2011-2013 | | Total |
| Level 1 (a) | \$ (4) | \$ - | | \$ (4) |
| Level 2 (b) | 2,410 | (222) | | 2,188 |
| Level 3 (c) | (2) | - | | (2) |
| Total MTM Risk Management | | | | |
| Contract Net Assets (Liabilities) | \$ 2,404 | \$ (222) | | \$ 2,182 |

| | Remainder | | | |
|-----------------------------------|-----------|-----------|--|----------|
| SWEPCo | 2010 | 2011-2013 | | Total |
| Level 1 (a) | \$ (4) | \$ - | | \$ (4) |
| Level 2 (b) | 1,570 | (464) | | 1,106 |
| Level 3 (c) | (2) | - | | (2) |
| Total MTM Risk Management | | | | |
| Contract Net Assets (Liabilities) | \$ 1,564 | \$ (464) | | \$ 1,100 |

(a) Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 1 inputs primarily consist of exchange traded contracts that exhibit sufficient frequency and volume to provide pricing information on an ongoing basis.

- (b) Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, exchange traded contracts where there was not sufficient market activity to warrant inclusion in Level 1 and OTC broker quotes that are corroborated by the same or similar transactions that have occurred in the market.
- (c) Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that the observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Level 3 inputs primarily consist of unobservable market data or are valued based on models and/or assumptions.
- (d) Dedesignated Risk Management Contracts are contracts that were originally MTM but were subsequently elected as normal under the accounting guidance for “Derivatives and Hedging.” At the time of the normal election, the MTM value was frozen and no longer fair valued. This will be amortized into Revenues over the remaining life of the contracts.

Credit Risk

Counterparty credit quality and exposure is generally consistent with that of AEP.

Value at Risk (VaR) Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates VaR to measure commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, at June 30, 2010, a near term typical change in commodity prices is not expected to have a material effect on net income, cash flows or financial condition.

The following table shows the end, high, average and low market risk as measured by VaR for the periods indicated:

| Company | End | Six Months Ended June 30, 2010 | | | End | Twelve Months Ended December 31, 2009 | | |
|---------|--------|-----------------------------------|---------|--------|--------|--|---------|--------|
| | | High (in thousands) | Average | Low | | High (in thousands) | Average | Low |
| APCo | \$ 191 | \$ 659 | \$ 259 | \$ 133 | \$ 275 | \$ 699 | \$ 333 | \$ 151 |
| OPCo | 142 | 545 | 219 | 103 | 201 | 530 | 244 | 113 |
| PSO | 6 | 70 | 16 | 3 | 10 | 34 | 12 | 4 |
| SWEPCo | 8 | 93 | 24 | 5 | 16 | 49 | 18 | 6 |

Management back-tests its VaR results against performance due to actual price movements. Based on the assumed 95% confidence interval, the performance due to actual price movements would be expected to exceed the VaR at least once every 20 trading days.

As the VaR calculations capture recent price movements, management also performs regular stress testing of the portfolio to understand the exposure to extreme price movements. Management employs a historical-based method whereby the current portfolio is subjected to actual, observed price movements from the last four years in order to ascertain which historical price movements translated into the largest potential MTM loss. Management then researches the underlying positions, price movements and market events that created the most significant exposure and report the findings to the Risk Executive Committee or the Commercial Operations Risk Committee as appropriate.

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on the Registrant Subsidiaries' outstanding debt as of June 30, 2010 and December 31, 2009, the estimated EaR on the Registrant Subsidiaries' debt portfolio was as follows:

| Company | June 30, 2010 | | December 31, 2009 | |
|---------|------------------|-----|----------------------|-------|
| | (in thousands) | | | |
| APCo | \$ | 770 | \$ | 1,837 |

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| | | |
|--------|-------|-------|
| CSPCo | 178 | 216 |
| I&M | 203 | 227 |
| OPCo | 1,222 | 1,373 |
| PSO | 77 | 119 |
| SWEPCo | 41 | 305 |

CONTROLS AND PROCEDURES

During the second quarter of 2010, management, including the principal executive officer and principal financial officer of each of AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo (collectively, the Registrants), evaluated the Registrants' disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrants that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to the Registrants' management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

As of June 30, 2010, these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives. The Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of their financial reporting and to maintain dynamic systems that change as events warrant.

There was no change in the Registrants' internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the second quarter of 2010 that materially affected, or is reasonably likely to materially affect, the Registrants' internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of material legal proceedings, see “Commitments, Guarantees and Contingencies,” of Note 4 incorporated herein by reference.

Item 1A. Risk Factors

Our Annual Report on Form 10-K for the year ended December 31, 2009 includes a detailed discussion of our risk factors. The information presented below amends and restates in their entirety certain of those risk factors that have been updated and should be read in conjunction with the risk factors and information disclosed in our 2009 Annual Report on Form 10-K.

General Risks of Our Regulated Operations

We may not fully recover all of the investment in and expenses related to the Turk Plant. (Applies to AEP and SWEPCo)

In June 2010, the APSC issued an order which reversed and set aside the previously granted CECPN. SWEPCo filed a notice with the APSC of its intent to proceed with construction of the Turk Plant but that SWEPCo no longer intends to pursue a CECPN to seek recovery of the originally approved 88 MW portion of Turk Plant costs in Arkansas retail rates. The parties that successfully challenged the granting of the CECPN filed a complaint with the Federal District Court for the Western District of Arkansas seeking an injunction to stop construction of the Turk Plant asserting claims of violations of federal and state laws.

In November 2008, SWEPCo received its required air permit approval from the Arkansas Department of Environmental Quality and commenced construction at the site. The Arkansas Pollution Control and Ecology Commission (APCEC) upheld the air permit. In February 2010, the parties who unsuccessfully appealed the air permit to the APCEC filed a notice of appeal with the Circuit Court of Hempstead County, Arkansas.

The wetlands permit was issued by the U.S. Army Corps of Engineers in December 2009. In February 2010, the Sierra Club, the Audubon Society and others filed a complaint in the Federal District Court for the Western District of Arkansas against the U.S. Army Corps of Engineers challenging the process used and the terms of the permit issued to SWEPCo authorizing certain wetland and stream impacts.

In January 2009, SWEPCo was granted CECPNs by the APSC to build three transmission lines and facilities authorized by the SPP and needed to transmit power from the Turk Plant. Intervenor appealed the CECPN decisions in April 2009 to the Arkansas Court of Appeals. In July 2010, the Hempstead County Hunting Club and other appellants filed with the Arkansas Court of Appeals emergency motions to stay the transmission CECPNs to prohibit SWEPCo from taking ownership of private property and undertaking construction of the transmission lines.

If SWEPCo is unable to complete the Turk Plant construction and place the Turk Plant in service or if SWEPCo cannot recover all of its investment in and expenses related to the Turk Plant, it would reduce future net income and cash flows and impact financial condition.

Ohio may require us to refund fuel costs that we have collected. (Applies to OPCo)

As required under the ESP orders, the PUCO selected an outside consultant to conduct the audit of the FAC for the period of January 2009 through December 2009. In May 2010, the outside consultant provided their confidential audit report of the FAC audit to the PUCO. The audit report included a recommendation that the PUCO should review whether any proceeds from a 2008 coal contract settlement agreement which totaled \$72 million should reduce OPG's FAC under-recovery balance. Of the total proceeds, approximately \$58 million was recognized as a reduction to fuel expense prior to 2009 and \$14 million will reduce fuel expense in 2009 and 2010. If the PUCO orders any portion of the \$58 million previously recognized gains be used to reduce the current year FAC deferral, it would reduce future net income and cash flows and impact financial condition.

Ohio may require us to refund rider revenue that we have collected. (Applies to CSPCo and OPCo)

The Industrial Energy Users-Ohio filed a notice of appeal of the 2009 and 2010 PUCO-approved Economic Development Rider (EDR) with the Supreme Court of Ohio. As of June 30, 2010, CSPCo and OPCo have incurred \$32 million and \$23 million, respectively, in EDR costs including carrying costs. Of these costs, CSPCo and OPCo have collected \$16 million and \$12 million, respectively, through the EDR, which CSPCo and OPCo began collecting in January 2010. The remaining \$16 million and \$11 million for CSPCo and OPCo, respectively, are recorded as EDR regulatory assets. If CSPCo and OPCo are not ultimately permitted to recover their deferrals or are required to refund revenue collected, it would reduce future net income and cash flows and impact financial condition.

Texas may require us to refund fuel costs that we have collected. (Applies to SWEPCo)

In May 2010, various intervenors, including the PUCT staff, filed testimony recommending disallowances ranging from \$3 million to \$30 million in SWEPCo's \$755 million fuel and purchase power costs reconciliation for the period January 2006 through March 2009. If the PUCT disallows any portion of SWEPCo's fuel and purchase power costs, it could reduce future net income and cash flows and possibly impact financial condition.

Our request for rate recovery in West Virginia may not be approved in its entirety. (Applies to AEP and APCo)

In May 2010, APCo and WPCo filed a request with the WVPSC to increase annual base rates by \$156 million based on an 11.75% return on common equity to be effective March 2011. If the WVPSC denies all or part of the requested rate recovery, it could reduce future net income and cash flows.

Oklahoma may require us to refund fuel costs that we have collected. (Applies to PSO)

In July 2009, the OCC initiated a proceeding to review PSO's fuel and purchased power adjustment clause for the calendar year 2008 and also initiated a prudence review of the related costs. In March 2010, the Oklahoma Attorney General and the OIEC recommended the fuel clause adjustment rider be amended so that the shareholder's portion of off-system sales margins sharing decrease from 25% to 10%. The OIEC also recommended that the OCC conduct a comprehensive review of all affiliate transactions during 2007 and 2008. In July 2010, additional testimony regarding the 2007 transfer of ERCOT trading contracts to AEP Energy Partners was filed. Included in this testimony were unquantified refund recommendations relating to re-pricing of contract transactions. If the OCC were to issue an unfavorable decision, it would reduce future net income and cash flows and impact financial condition.

Our request for rate recovery in Oklahoma may not be approved in its entirety. (Applies to AEP and PSO)

In July 2010, PSO filed a request with the OCC to increase annual rates by \$82 million, including \$30 million that is currently being recovered through a rider. The requested increase includes a \$24 million increase in depreciation and an 11.5% return on common equity. If the OCC denies all or part of the requested rate recovery, it could reduce future net income and cash flows.

Risks Related to Owning and Operating Generation Assets and Selling Power

We may not fully recover the costs of repairing or replacing damaged equipment in Cook Plant Unit 1 and may be required to pay additional
accidental outage insurance proceeds to ratepayers. (Applies to AEP and I&M)

Cook Plant Unit 1 is a 1,084 MW nuclear generating unit located in Bridgman, Michigan. In September 2008, I&M shut down Unit 1 due to turbine vibrations, caused by blade failure, which resulted in significant turbine damage and a small fire on the electric generator. Unit 1 resumed operations in December 2009 at slightly reduced power, but repair

of the property damage and replacement of the turbine rotors and other equipment are estimated to cost approximately \$395 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process.

In March 2009, the IURC approved a settlement agreement with intervenors to collect a prior under-recovered fuel balance. Under the settlement agreement, a subdocket was established to consider issues relating to the Unit 1 shutdown including the treatment of the accidental outage insurance proceeds. Separately, in March 2010, I&M filed its 2009 PSCR reconciliation with the MPSC. The filing included an adjustment related to the incremental fuel cost of replacement power due to the Cook Plant Unit 1 outage. If any fuel clause revenues or accidental outage insurance proceeds have to be refunded, it would reduce future net income and cash flows and impact financial condition.

Financial derivatives reforms could increase the liquidity needs and costs of our commercial trading operations. (Applies to each registrant.)

In July 2010, federal legislation was enacted to reform financial markets that significantly alter how over-the-counter (OTC) derivatives are regulated. The law increased regulatory oversight of OTC energy derivatives, including (1) requiring standardized OTC derivatives to be traded on registered exchanges regulated by the Commodity Futures Trading Commission (CFTC), (2) imposing new and potentially higher capital and margin requirements and (3) authorizing the establishment of overall volume and position limits. The law gives the CFTC authority to exempt end users of energy commodities which could reduce, but not eliminate, the applicability of these measures to us and other end users. These requirements could cause our OTC transactions to be more costly and have an adverse effect on our liquidity due to additional capital requirements. In addition, as these reforms aim to standardize OTC products it could limit the effectiveness of our hedging programs because we would have less ability to tailor OTC derivatives to match the precise risk we are seeking to protect.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The following table provides information about purchases by AEP or its publicly-traded subsidiaries during the quarter ended June 30, 2010 of equity securities that are registered by AEP or its publicly-traded subsidiaries pursuant to Section 12 of the Exchange Act:

ISSUER PURCHASES OF EQUITY SECURITIES

| Period | Total Number of Shares Purchased | Average Price Paid per Share | 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 |
|------------------------|--|---------------------------------|--|---|
| 04/01/10 – 04/30/10 | 3,759(a) | \$ 80.00 | - | \$ - |
| 05/01/10 – 05/31/10 | 2(b) | 66.75 | - | - |
| 06/01/10 – 06/30/10 | - | - | - | - |

(a) PSO purchased 3,759 shares of its 4.24% cumulative preferred stock in a privately-negotiated transaction outside of an announced program.

(b) I&M purchased 1 share of its 4.125% cumulative preferred stock and OPCo purchased 1 share of its 4.50% cumulative preferred stock in privately-negotiated transactions outside of an announced program.

Item 5. Other Information

NONE

Item 6. Exhibits

AEP, APCo, OPCo, PSO and SWEPCo

10 – Amended and Restated AEP System Long-term Incentive Plan.

AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

12 – Computation of Consolidated Ratio of Earnings to Fixed Charges.

AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

31(a) – Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31(b) – Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

AEP, APCo, CSPCo, I&M, OPCo, PSO and SWEPCo

32(a) – Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.

32(b) – Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.

SIGNATURE

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. The signature for each undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

APPALACHIAN POWER COMPANY
COLUMBUS SOUTHERN POWER COMPANY
INDIANA MICHIGAN POWER COMPANY
OHIO POWER COMPANY
PUBLIC SERVICE COMPANY OF OKLAHOMA
SOUTHWESTERN ELECTRIC POWER COMPANY

By: /s/Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

Date: July 30, 2010

