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

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

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
INDEX TO QUARTERLY REPORTS ON FORM 10-Q
June 30, 2010

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.
CO2	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.

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.
SO2	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.
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- 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.

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Turk Plant

SWEPCo 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. SWEPCo owns 73% (440 MW) of the Turk Plant and will operate the completed facility. SWEPCo'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 SWEPCo'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 SWEPCo related to the reversal of the APSC's earlier grant of a CECPN for SWEPCo's 88 MW Arkansas portion of the Turk Plant. As a result, in June 2010, SWEPCo filed 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 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 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.

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 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.

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,	
Energy/Delivery Summary	2010	2009	2010	2009
	(in millions of KWH)			
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.

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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.

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.

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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

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

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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	Six Months Ended June 30, 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 CO_2 capture validation facility, which was placed into service in September 2009. APCo also constructed and owns the necessary facilities to store the CO_2. 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, NOx, 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 NOx 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 NOx. 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

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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 CO_2 emissions might be achieved through new legislation, Congress has yet to enact such legislation. The Federal EPA continues to take action to regulate CO_2 emissions under the existing requirements of the CAA. The Federal EPA issued a final endangerment finding for CO_2 emissions from new motor vehicles in December 2009 and final rules for new motor vehicles in May 2010. The Federal EPA determined that CO_2 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 CO_2 emissions through the NSR prevention of significant deterioration and Title V operating permit programs. The Federal EPA is reconsidering whether to include CO_2 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 CO_2 emissions. If substantial CO_2 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 CO_2 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 CO_2 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 CO_2 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 CO_2 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 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, 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.

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	Net Exposure	Number of Counterparties >10% of Net Exposure	Net Exposure of Counterparties >10%
	(in millions, except number of counterparties)				
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

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						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
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
CURRENT LIABILITIES		(in millions)		
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

	2010	2009
(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

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

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

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 DHLC 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 DHLC.

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.

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 the Consolidated Balance Sheet	Maximum 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 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	$ 0.67
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	$ 1.54
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, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 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 – Barging 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, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 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 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 CO_2 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. Intervenors 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.

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.

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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. 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.

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

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 Three Months Ended June 30, 2010	Pension Plans Three Months Ended June 30, 2009	Other Postretirement Benefit Plans Three Months Ended June 30, 2010	Other Postretirement Benefit Plans Three Months Ended June 30, 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 Six Months Ended June 30, 2010	Pension Plans Six Months Ended June 30, 2009	Other Postretirement Benefit Plans Six Months Ended June 30, 2010	Other Postretirement Benefit Plans Six Months Ended June 30, 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.

		Nonutility Operations				
	Utility Operations	AEP River Operations	Generation 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			
	Utility		Generation and	All Other	Reconciling

	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	AEP River Operations (Nonutility Operations)	Generation and Marketing (Nonutility Operations)	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
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	AEP River Operations (Nonutility Operations)	Generation and Marketing (Nonutility Operations)	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
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

	Utility Operations	AEP River Operations (Nonutility Operations)	Generation and Marketing (Nonutility Operations)	All Other (a)	Reconciling 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

	Utility Operations	AEP River Operations	Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
			(in millions)			
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

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

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

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)(c)	Other (a) (b)	Total
			(in millions)		
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

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

		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.

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	Total
		(in millions)	
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	Total
		(in millions)	
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 Fixed Income Security		
Type of Input	United States Government	Corporate Debt	State and Local 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	

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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:

	June 30, 2010			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(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

	December 31, 2009			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(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, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 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

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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

Assets:	Level 1	Level 2	Level 3 (in millions)	Other	Total
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

Assets:	Level 1	Level 2	Level 3 (in millions)	Other	Total
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

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Three Months Ended June 30, 2009	Net Risk Management Assets (Liabilities) (in millions)
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

Six Months Ended June 30, 2009	Net Risk Management Assets (Liabilities) (in millions)
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:

	June 30, 2010				December 31, 2009			
Type of Debt	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, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 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

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.

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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)

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	

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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.

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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.

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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.

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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.

COLUMBUS SOUTHERN POWER COMPANY
AND SUBSIDIARIES

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 2010	Three Months Ended 2009	Six Months Ended 2010	Six Months Ended 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					

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.

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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.

INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

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.

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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.

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

	2010	2009
CURRENT LIABILITIES	(in thousands)	
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.

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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)

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.

OHIO POWER COMPANY CONSOLIDATED

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 OPCo’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 2010	Three Months Ended 2009	Six Months Ended 2010	Six Months Ended 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 Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
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)

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.

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.

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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 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 $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

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.

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 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 $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, 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 $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)

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

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.

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

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.

SWEPCo is the primary beneficiary of Sabine. As of January 1, 2010, SWEPCo 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 SWEPCo each hold a significant variable interest in AEPSC. I&M and CSPCo each hold a significant variable interest in AEGCo. SWEPCo holds a significant variable interest in DHLC.

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 SWEPCo'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)

		DCC
ASSETS		
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)

		DCC
ASSETS		
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, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 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 As Reported in the Balance Sheet	June 30, 2010 Maximum Exposure	December 31, 2009 As Reported in the Balance Sheet	December 31, 2009 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, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 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:

	June 30, 2010		December 31, 2009	
Company	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:

	Three Months Ended June 30, 2010		Six Months Ended June 30, 2010	
Company	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. Intervenors 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:			
APCo	$ 232,292	November 2010 to April 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 CO_2 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 CO_2 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 CO_2 emissions or that the Federal EPA could regulate CO_2 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.

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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
Conesville	CSPCo/Dayton Power and Light Company/ 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 Three Months Ended June 30,		Other Postretirement Benefit Plans 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 Six Months Ended June 30,		Other Postretirement Benefit Plans Six Months Ended June 30,	
	2010	2009	2010	2009

	(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 Three Months Ended June 30,		Other Postretirement Benefit Plans 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 Six Months Ended June 30,		Other Postretirement Benefit Plans 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 Three Months Ended June 30,		Other Postretirement Benefit Plans 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 Six Months Ended June 30,		Other Postretirement Benefit Plans 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)

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 Three Months Ended June 30,		Other Postretirement Benefit Plans 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 Six Months Ended June 30,		Other Postretirement Benefit Plans 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 Three Months Ended June 30,		Other Postretirement Benefit Plans 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 Six Months Ended June 30,		Other Postretirement Benefit Plans 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)

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

SWEPCo

	Pension Plans Three Months Ended June 30,		Other Postretirement Benefit Plans 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 Six Months Ended June 30,		Other Postretirement Benefit Plans 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:

	Paid as of June 30, 2010		Remainder Expected to be Paid in 2010	
Company	Pension Plans	Other Postretirement Benefit Plans	Pension Plans	Other Postretirement 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.

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

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

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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:

	June 30, 2010		December 31, 2009	
Company	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 Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Other (a) (b)	Total
			(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 Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Other (a) (b)	Total
			(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

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Fair Value of Derivative Instruments
June 30, 2010

CSPCo

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

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Fair Value of Derivative Instruments
June 30, 2010

I&M

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Other (a) (b)	Total
			(in thousands)		
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 Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Other (a) (b)	Total
			(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

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Fair Value of Derivative Instruments
June 30, 2010

OPCo

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

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (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

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (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)

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Fair Value of Derivative Instruments
June 30, 2010

SWEPCo

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

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)	Other (a) (b)	Total
			(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	OPCo	PSO	SWEPCo
			(in thousands)			
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	OPCo	PSO	SWEPCo
			(in thousands)			
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

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

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)

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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)

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	OPCo	PSO	SWEPCo
			(in thousands)			
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	OPCo	PSO	SWEPCo
			(in thousands)			
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)

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

	Hedging Assets (a)		Hedging Liabilities (a)		AOCI Gain (Loss) Net of Tax	
Company	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	Interest Rate and Foreign Currency	Maximum Term for Exposure to Variability of Future Cash Flows
	(in thousands)		(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

	Hedging Assets (a)		Hedging Liabilities (a)		AOCI Gain (Loss) Net of Tax	
Company	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	Additional Settlement Liability if Cross Default Provision is Triggered
		(in thousands)	
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	Additional Settlement Liability if Cross Default Provision is Triggered
		(in thousands)	
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 Fixed Income Security		
Type of Input	United States Government	Corporate Debt	State and Local 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	

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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:

	June 30, 2010		December 31, 2009	
Company	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.

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

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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

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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

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.

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	OPCo	PSO	SWEPCo
			(in thousands)			
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	OPCo	PSO	SWEPCo
			(in thousands)			
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	Decrease in Net Income
		(in thousands)	
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

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

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	Average Loans to Utility Money Pool	Loans to (Borrowings) to/from Utility Money Pool as of June 30, 2010	Authorized Short-term Borrowing Limit
	(in thousands)					
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	Six Months Ended June 30, 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, 2010	2009	Average Interest Rate for Funds Loaned to the Utility Money Pool for the Six Months Ended June 30, 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 is described in the following table:

Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Borrowings from Utility Money Pool as of June 30, 2010
		(in thousands)		
$ 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:

Six Months Ended June 30,	Maximum Interest Rates for Funds Borrowed from the Utility Money Pool	Minimum Interest Rates for Funds Borrowed from the Utility Money Pool	Maximum Interest Rates for Funds Loaned to the Utility Money Pool	Minimum Interest Rates for Funds Loaned to the Utility Money Pool	Average Interest Rates for Funds Borrowed from the Utility Money Pool	Average Interest Rates for Funds Loaned to the Utility Money Pool
2010	0.51 %	0.09 %	- %	- %	0.24 %	- %

Short-term Debt

The Registrant Subsidiaries' outstanding short-term debt was as follows:

		June 30, 2010			December 31, 2009		
Company	Type of Debt		Outstanding Amount (in thousands)	Interest Rate (b)		Outstanding Amount (in thousands)	Interest Rate (b)
SWEPCo	Line 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, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 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, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 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, NOx, 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 NOx 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 NOx. 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 NOx 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.

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)

APCo	Remainder 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

OPCo	Remainder 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

PSO	Remainder 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

SWEPCo	Remainder 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:

	Six Months Ended June 30, 2010				Twelve Months Ended December 31, 2009			
Company	End	High	Average	Low	End	High	Average	Low
	(in thousands)				(in thousands)			
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

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. Intervenors appealed the CECPN decisions in April 2009 to the Arkansas Court of Appeals. In July 2010, the Hempsted 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 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.

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.

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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