DICE HOLDINGS, INC.
Form 8-K
August 16, 2011

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) August 16, 2011

DICE HOLDINGS, INC.
(Exact name of registrant as specified in its charter)

DELAWARE	001-33584	20-3179218
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

1040 AVENUE OF THE AMERICAS, 16TH FLOOR, NEW YORK, NY	10018
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code (212) 725-6550

(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01 Other Events.

On August 16, 2011, Dice Holdings, Inc. issued a press release announcing that its Board of Directors has authorized the purchase of up to $30 million of its common stock pursuant to a stock repurchase program. A copy of the press release is attached as Exhibit 99.1 to this Current Report on Form 8-K and is incorporated herein by reference.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits

Exhibit No.	Description
99.1	Press Release dated August 16, 2011.

SIGNATURES

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

DICE HOLDINGS, INC.

Date: August 16, 2011	By:	/s/ Brian P. Campbell Name: Brian P. Campbell Title: Vice President and General Counsel

Exhibit Index

Exhibit No.	Description
99.1	Press Release Dice Holdings, Inc. dated August 16, 2011.

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SUPPLEMENTARY INFORMATION

Cash Paid for Interest, Net of Capitalized Amounts	$ 37,915	$ 55,152
Net Cash Paid (Received) for Income Taxes	(18,520)	4,423
Noncash Acquisitions Under Capital Leases	13,572	2,802
Construction Expenditures Included in Accounts Payable at September 30,	5,254	7,315

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 161.

PUBLIC SERVICE COMPANY OF OKLAHOMA
INDEX TO CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF
REGISTRANT SUBSIDIARIES

The condensed notes to PSO's condensed 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 161.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

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SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

RESULTS OF OPERATIONS

Third Quarter of 2010 Compared to Third Quarter of 2009

Reconciliation of Third Quarter of 2009 to Third Quarter of 2010
Income Before Extraordinary Loss
(in millions)

Third Quarter of 2009	$	65	
Changes in Gross Margin:			
Retail Margins (a)		49	
Transmission Revenues		(1	)
Other Revenues		(11	)
Total Change in Gross Margin		37	
Total Expenses and Other:			
Other Operation and Maintenance		5	
Depreciation and Amortization		5	
Taxes Other Than Income Taxes		(1	)
Other Income		(5	)
Interest Expense		(7	)
Equity Earnings of Unconsolidated Subsidiaries		1	
Total Expenses and Other		(2	)
Income Tax Expense		(18	)
Third Quarter of 2010	$	82	

(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 $49 million primarily due to:
  - An $18 million increase in base rates in Arkansas and Texas.
  - A $16 million increase in weather-related usage primarily due to a 35% increase in cooling degree days.
  - A $6 million increase in fuel recovery primarily due to lower capacity costs and increased wholesale fuel recovery.
  - A $5 million increase in industrial sales due to higher demand.
- Other Revenues decreased $11 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.

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

- Other Operation and Maintenance expenses decreased $5 million primarily due to:
  - An $11 million decrease in expenses for coal deliveries from SWEPCo's mining subsidiary, DHLC. The decreased expenses for coal deliveries were offset by a corresponding decrease in revenues from mining operations as discussed above.

  This decrease was partially offset by:
  - A $7 million increase in distribution maintenance resulting primarily from storm-related amortization expense.
- Depreciation and Amortization expenses decreased $5 million primarily due to lower Arkansas and Texas depreciation resulting from the Arkansas and Texas base rate orders and the deconsolidation of DHLC, partially offset by plant additions including the Stall Unit.
- Other Income decreased $5 million primarily due to a decrease in the equity component of AFUDC as a result of the completion of the Stall Unit construction project in June 2010.
- Interest Expense increased $7 million primarily due to increased long-term debt outstanding.
- Income Tax Expense increased $18 million primarily due to an increase in pretax book income and other book/tax differences accounted for on a flow-through basis.

Nine Months Ended September 30, 2010 Compared to Nine Months Ended September 30, 2009

Reconciliation of Nine Months Ended September 30, 2009 to Nine Months Ended September 30, 2010
Income Before Extraordinary Loss
(in millions)

Nine Months Ended September 30, 2009	$	113
Changes in Gross Margin:		
Retail Margins (a)		91
Off-system Sales		1
Transmission Revenues		1
Other Revenues		(29)
Total Change in Gross Margin		64
Total Expenses and Other:		
Other Operation and Maintenance		(17)
Depreciation and Amortization		14
Taxes Other Than Income Taxes		(2)
Other Income		3
Interest Expense		(12)
Equity Earnings of Unconsolidated Subsidiaries		2
Total Expenses and Other		(12)
Income Tax Expense		(26)
Nine Months Ended September 30, 2010	$	139

(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 $91 million primarily due to:
  - A $32 million increase in weather-related usage primarily due to a 42% increase in heating degree days and a 30% increase in cooling degree days.
  - A $31 million increase in base rates in Arkansas and Texas.
  - An $11 million increase in fuel recovery primarily due to lower capacity costs and increased wholesale fuel recovery.
  - An $11 million increase in industrial sales due to higher demand.
- Other Revenues decreased $29 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.

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

- Other Operation and Maintenance expenses increased $17 million primarily due to:
  - A $28 million increase due to expenses related to the cost reduction initiatives.
  - 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.
  - A $4 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 $24 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 $14 million primarily due to lower Arkansas and Texas depreciation resulting from the Arkansas and Texas base rate orders and the deconsolidation of DHLC, partially offset by plant additions including the Stall Unit.
- Other Income increased $3 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. This increase was partially offset by decreases in approved return on common equity, the completion of the Stall Unit construction project in June 2010 and the discontinuance of AFUDC in Arkansas related to Turk Plant construction.
- Interest Expense increased $12 million primarily due to increased long-term debt outstanding.
- Income Tax Expense increased $26 million primarily due to an increase in pretax book income and other book/tax differences accounted for on a flow-through basis.

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 230 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 nine months ended September 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	168,196	335,922
Net Cash Flows Used for Investing Activities	(449,053)	(472,183)
Net Cash Flows from Financing Activities	281,078	136,440
Net Increase in Cash and Cash Equivalents	221	179
Cash and Cash Equivalents at End of Period	$ 1,882	$ 2,089

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Operating Activities

Net Cash Flows from Operating Activities were $168 million in 2010. SWEPCo produced Net Income of $139 million during the period and had a noncash item of $95 million for Depreciation and Amortization, partially offset by $37 million for Allowance for Equity Funds Used During Construction. SWEPCo contributed $27 million to the qualified pension trust. 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 $49 million inflow from Accrued Taxes, Net was the result of an increase in accruals related to federal and property taxes. The $36 million outflow from Accounts Payable was primarily due to decreases related to customer accounts factored, net and purchased power payable. The $28 million inflow from Fuel, Materials and Supplies was primarily due to decreased coal and lignite inventories. The $24 million outflow from Accounts Receivable, Net was primarily due to increased affiliated receivables.

Net Cash Flows from Operating Activities were $336 million in 2009. SWEPCo produced Net Income of $107 million during the period and had a noncash item of $109 million for Depreciation and Amortization, partially offset by $32 million in Allowance for Equity Funds Used During Construction and $21 million in 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 $81 million inflow from Accounts Receivable, Net was primarily due to the receipt of payment for SIA from the AEP East companies. The $53 million outflow from Other Current Liabilities was due to a decrease in check clearing, a refund to wholesale customers for the SIA and payments of employee-related expenses. The $50 million inflow from Accrued Taxes, Net was the result of an increase in accruals related to federal and property taxes. The $25 million inflow from Accounts Payable was primarily due to increases in accruals related to tax payments, partially offset by a decrease in customer accounts factored, net. The $20 million outflow from Accrued Interest was primarily due to timing between accruals and payments for Senior Unsecured Notes. The $62 million inflow from Fuel Over/Under-Recovery, Net was the result of a surcharge to customers in Texas for under-recovered fuel and a decrease in fuel costs.

Investing Activities

Net Cash Flows Used for Investing Activities during 2010 and 2009 were $449 million and $472 million, respectively. Construction Expenditures of $288 million and $470 million in 2010 and 2009, respectively, were primarily related to new generation projects at the Turk Plant and Stall Unit. SWEPCo's net increase in loans to the Utility Money Pool during 2010 and 2009 were $162 million and $107 million, respectively. Proceeds from Sales of Assets in 2009 primarily included $104 million related to the sale of a portion of Turk Plant to joint owners.

Financing Activities

Net Cash Flows from Financing Activities were $281 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 $136 million during 2009. SWEPCo received a capital contribution from Parent of $143 million and $12 million from proceeds on sale leaseback of a utility property.

Long-term debt issuances and retirements during the first nine 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.

EXECUTIVE OVERVIEW

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 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. See “2009 Texas Base Rate Filing” 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 $132 million for transmission, excluding AFUDC. SWEPCo's share is currently estimated to cost $1.3 billion, excluding AFUDC, plus an additional $132 million for transmission, excluding AFUDC. Notices of appeal are outstanding at the Circuit Court of Hempstead County, Arkansas and the Federal Court of Appeals. Matters are also outstanding at the Texas Court of Appeals, the APSC and the LPSC. See "Turk Plant" section of Note 3.

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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 161. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

See the "Executive Overview" section of "Combined Management's Discussion and Analysis of Registrant Subsidiaries" section beginning on page 230 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 230 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 230 for a discussion of risk management activities.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2010 and 2009
(in thousands)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2010	2009	2010	2009
REVENUES				
Electric Generation, Transmission and Distribution	$459,013	$392,616	$1,139,748	$1,021,991
Sales to AEP Affiliates	21,356	9,420	43,920	23,470
Lignite Revenues – Nonaffiliated	-	12,334	-	30,572
Other Revenues	613	604	1,585	1,525
TOTAL REVENUES	480,982	414,974	1,185,253	1,077,558
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	194,340	161,879	452,279	405,329
Purchased Electricity for Resale	29,794	30,413	94,521	85,149
Purchased Electricity from AEP Affiliates	4,191	6,865	18,154	30,395
Other Operation	52,839	64,686	193,357	178,456
Maintenance	23,979	17,267	69,531	67,283
Depreciation and Amortization	31,828	36,714	94,939	109,065
Taxes Other Than Income Taxes	15,583	14,127	47,058	44,995
TOTAL EXPENSES	352,554	331,951	969,839	920,672
OPERATING INCOME	128,428	83,023	215,414	156,886
Other Income (Expense):				
Interest Income	186	388	434	1,205
Allowance for Equity Funds Used During Construction	8,651	12,932	36,630	31,706
Interest Expense	(23,459)	(16,605)	(63,478)	(51,894)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	113,806	79,738	189,000	137,903
Income Tax Expense	32,870	14,680	51,733	25,367
Equity Earnings of Unconsolidated Subsidiaries	749	-	2,206	-
INCOME BEFORE EXTRAORDINARY LOSS	81,685	65,058	139,473	112,536
EXTRAORDINARY LOSS, NET OF TAX	-	-	-	(5,325)
NET INCOME	81,685	65,058	139,473	107,211
Less: Net Income Attributable to Noncontrolling Interest	774	1,022	3,198	2,971
NET INCOME ATTRIBUTABLE TO SWEPCo SHAREHOLDERS	80,911	64,036	136,275	104,240

Less: Preferred Stock Dividend Requirements	58	58	172	172
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$80,853	$63,978	$136,103	$104,068

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

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 161.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 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		142,500				142,500
Common Stock Dividends – Nonaffiliated					(2,886)	(2,886)
Preferred Stock Dividends			(172)			(172)
Other Changes in Equity		2,476	(2,476)			-
SUBTOTAL – EQUITY						1,388,371
COMPREHENSIVE INCOME						
Other Comprehensive Income, Net of Taxes:						
Cash Flow Hedges, Net of Tax of $421				782		782
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $8,919				16,563		16,563
NET INCOME			104,240		2,971	107,211
TOTAL COMPREHENSIVE INCOME						124,556
TOTAL EQUITY – SEPTEMBER 30, 2009	$ 135,660	$ 674,979	$ 716,702	$ (14,775)	$ 361	$ 1,512,927
TOTAL EQUITY – DECEMBER 31, 2009	$ 135,660	$ 674,979	$ 726,478	$ (12,991)	$ 31	$ 1,524,157
Common Stock Dividends – Nonaffiliated					(2,966)	(2,966)

Preferred Stock Dividends			(172)			(172)
SUBTOTAL – EQUITY						1,521,019
COMPREHENSIVE INCOME						
Other Comprehensive Income, Net of Taxes:						
Cash Flow Hedges, Net of Tax of $248				461		461
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $379				703		703
NET INCOME			136,275		3,198	139,473
TOTAL COMPREHENSIVE INCOME						140,637
TOTAL EQUITY – SEPTEMBER 30, 2010	$ 135,660	$ 674,979	$ 862,581	$ (11,827)	$ 263	$ 1,661,656

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 161.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2010 and December 31, 2009
(in thousands)
(Unaudited)

	2010	2009
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,882	$ 1,661
Advances to Affiliates	213,689	34,883
Accounts Receivable:		
Customers	23,833	46,657
Affiliated Companies	42,393	19,542
Miscellaneous	23,753	9,952
Allowance for Uncollectible Accounts	(454)	(64)
Total Accounts Receivable	89,525	76,087
Fuel		
(September 30, 2010 amount includes $31,649 related to Sabine)	86,154	121,453
Materials and Supplies	48,770	54,484
Risk Management Assets	2,017	3,049
Deferred Income Tax Benefits	14,470	13,820
Accrued Tax Benefits	2,859	16,164
Regulatory Asset for Under-Recovered Fuel Costs	7,622	1,639
Prepayments and Other Current Assets	20,388	20,503
TOTAL CURRENT ASSETS	487,376	343,743
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	2,267,397	1,837,318
Transmission	906,837	870,069
Distribution	1,476,596	1,447,559
Other Property, Plant and Equipment		
(September 30, 2010 amount includes $224,987 related to Sabine)	640,697	733,310
Construction Work in Progress	1,003,889	1,176,639
Total Property, Plant and Equipment	6,295,416	6,064,895
Accumulated Depreciation and Amortization		
(September 30, 2010 amount includes $89,703 related to Sabine)	2,080,258	2,086,333
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	4,215,158	3,978,562
OTHER NONCURRENT ASSETS		
Regulatory Assets	295,590	268,165
Long-term Risk Management Assets	419	84
Deferred Charges and Other Noncurrent Assets	80,591	49,479
TOTAL OTHER NONCURRENT ASSETS	376,600	317,728
TOTAL ASSETS	$ 5,079,134	$ 4,640,033

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 161.

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SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
September 30, 2010 and December 31, 2009
(Unaudited)

	2010	2009
	(in thousands)	
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 168,300	$ 160,870
Affiliated Companies	45,767	59,818
Short-term Debt – Nonaffiliated	3,170	6,890
Long-term Debt Due Within One Year – Nonaffiliated	41,135	4,406
Long-term Debt Due Within One Year – Affiliated	-	50,000
Risk Management Liabilities	523	844
Customer Deposits	43,467	41,269
Accrued Taxes	58,319	24,720
Accrued Interest	18,088	33,179
Obligations Under Capital Leases	12,679	14,617
Regulatory Liability for Over-Recovered Fuel Costs	5,377	13,762
Provision for SIA Refund	20,766	19,307
Other Current Liabilities	45,115	71,781
TOTAL CURRENT LIABILITIES	462,706	501,463
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,728,322	1,419,747
Long-term Risk Management Liabilities	272	221
Deferred Income Taxes	514,576	485,936
Regulatory Liabilities and Deferred Investment Tax Credits	385,825	333,935
Asset Retirement Obligations	49,720	60,562
Employee Benefits and Pension Obligations	98,684	125,956
Obligations Under Capital Leases	114,017	134,044
Deferred Credits and Other Noncurrent Liabilities	58,659	49,315
TOTAL NONCURRENT LIABILITIES	2,950,075	2,609,716
TOTAL LIABILITIES	3,412,781	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	862,581	726,478
Accumulated Other Comprehensive Income (Loss)	(11,827)	(12,991)
TOTAL COMMON SHAREHOLDER'S EQUITY	1,661,393	1,524,126
Noncontrolling Interest	263	31
TOTAL EQUITY	1,661,656	1,524,157
TOTAL LIABILITIES AND EQUITY	$5,079,134	$4,640,033

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 161.

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SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2010 and 2009
(in thousands)
(Unaudited)

	2010	2009
OPERATING ACTIVITIES		
Net Income	$139,473	$107,211
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	94,939	109,065
Deferred Income Taxes	1,227	(20,571)
Extraordinary Loss, Net of Tax	-	5,325
Allowance for Equity Funds Used During Construction	(36,630)	(31,706)
Mark-to-Market of Risk Management Contracts	230	510
Pension Contributions to Qualified Plan Trust	(26,684)	-
Fuel Over/Under-Recovery, Net	(14,371)	61,880
Change in Other Noncurrent Assets	(16,101)	13,498
Change in Other Noncurrent Liabilities	41,231	4,539
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(23,562)	81,322
Fuel, Materials and Supplies	27,811	4,396
Accounts Payable	(35,890)	24,584
Accrued Taxes, Net	49,249	50,027
Accrued Interest	(15,085)	(19,816)
Other Current Assets	(1,864)	(1,017)
Other Current Liabilities	(15,777)	(53,325)
Net Cash Flows from Operating Activities	168,196	335,922
INVESTING ACTIVITIES		
Construction Expenditures	(288,043)	(470,379)
Change in Advances to Affiliates, Net	(161,873)	(106,662)
Proceeds from Sales of Assets	1,337	105,500
Other Investing Activities	(474)	(642)
Net Cash Flows Used for Investing Activities	(449,053)	(472,183)
FINANCING ACTIVITIES		
Capital Contribution from Parent	-	142,500
Issuance of Long-term Debt – Nonaffiliated	399,394	-
Borrowings from Revolving Credit Facilities	74,449	90,478
Change in Advances from Affiliates, Net	-	(2,526)
Retirement of Long-term Debt – Nonaffiliated	(53,500)	(3,304)
Retirement of Long-term Debt – Affiliated	(50,000)	-
Repayments to Revolving Credit Facilities	(78,170)	(92,377)
Proceeds from Sale/Leaseback	-	12,222
Principal Payments for Capital Lease Obligations	(8,873)	(7,853)
Dividends Paid on Common Stock – Nonaffiliated	(2,966)	(2,971)
Dividends Paid on Cumulative Preferred Stock	(172)	(172)

Other Financing Activities	916	443
Net Cash Flows from Financing Activities	281,078	136,440
Net Increase in Cash and Cash Equivalents	221	179
Cash and Cash Equivalents at Beginning of Period	1,661	1,910
Cash and Cash Equivalents at End of Period	$1,882	$2,089
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$72,270	$82,033
Net Cash Paid (Received) for Income Taxes	25,575	(6,196)
Noncash Acquisitions Under Capital Leases	653	26,175
Construction Expenditures Included in Accounts Payable at September 30,	101,017	60,219

See Condensed Notes to Condensed Financial Statements of Registrant Subsidiaries beginning on page 161.

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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 161.

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 nine months ended September 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 and DCC Fuel II LLC. 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 September 30, 2010 and 2009 were $30 million and $34 million, respectively, and for the nine months ended September 30, 2010 and 2009 were $103 million and $95 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 September 30, 2010 and 2009 were $14 million and $12 million, respectively, and for the nine months ended September 30, 2010 and 2009 were $40 million and $31 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 September 30, 2010. As of September 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
September 30, 2010
(in millions)

		Sabine
ASSETS		
Current Assets	$	42
Net Property, Plant and Equipment		142
Other Noncurrent Assets		35
Total Assets	$	219
LIABILITIES AND EQUITY		
Current Liabilities	$	26
Noncurrent Liabilities		193
Equity		-
Total Liabilities and Equity	$	219

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:

	September 30, 2010	
	As Reported on the Consolidated	Maximum

	Balance Sheet		Exposure
		(in millions)	
Capital Contribution from SWEPCo	$ 7		$ 7
Retained Earnings	2		2
SWEPCo's Guarantee of Debt	-		42
Total Investment in DHLC	$ 9		$ 51

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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 Fuel) were formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel 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 for the nine months ended September 30, 2010 were $22 million. No payments were made to DCC Fuel during the third quarter of 2010 and during the year 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 Fuel, management concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The capital leases are eliminated upon consolidation. See the tables below for the classification of DCC Fuel'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 are eliminated upon consolidation.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
VARIABLE INTEREST ENTITIES
September 30, 2010
(in millions)

		DCC Fuel
ASSETS		
Current Assets	$	92
Net Property, Plant and Equipment		118
Other Noncurrent Assets		80
Total Assets	$	290
LIABILITIES AND EQUITY		
Current Liabilities	$	65
Noncurrent Liabilities		225
Equity		-
Total Liabilities and Equity	$	290

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
VARIABLE INTEREST ENTITIES
December 31, 2009
(in millions)

		DCC Fuel
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

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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 September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
	(in millions)			
APCo	$ 51	$ 50	$ 177	$ 146
CSPCo	30	31	104	91
I&M	31	32	106	93
OPCo	41	43	153	130
PSO	23	21	78	64
SWEPCo	31	35	110	94

The carrying amount and classification of variable interest in AEPSC's accounts payable are as follows:

Company	September 30, 2010 As Reported in the Balance Sheet	September 30, 2010 Maximum Exposure	December 31, 2009 As Reported in the Balance Sheet	December 31, 2009 Maximum Exposure
	(in millions)			
APCo	$ 18	$ 18	$ 23	$ 23
CSPCo	10	10	13	13
I&M	11	11	13	13
OPCo	14	14	18	18
PSO	6	6	9	9
SWEPCo	11	11	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 September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
	(in millions)			
CSPCo	$ 44	$ 28	$ 81	$ 60
I&M	64	59	168	183

The carrying amount and classification of variable interest in AEGCo’s accounts payable are as follows:

September 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	$ 9	$ 9	$ 6	$ 6
I&M	28	28	23	23

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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 $40 million of lignite from DHLC and recorded these costs in Fuel on its Condensed Consolidated Balance Sheet at September 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 nine months ended September 30, 2010:

	Nine Months Ended September 30, 2010	
Company	Reported in Revenues	Reported in Expenses
	(in thousands)	
APCo	$ 6,631	$ 3,635
CSPCo	3,689	1,963
I&M	3,721	1,980
OPCo	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 September 30, 2010/2009	Nine Months Ended September 30, 2010/2009
(in thousands)	
$ 9,285	$ 19,718

Adjustments to Reported Cash Flows

In the Financing Activities section of SWEPCo's Condensed Consolidated Statements of Cash Flows for the nine months ended September 30, 2009, SWEPCo corrected the presentation of borrowings on lines of credit of $90 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 $92 million for the nine months ended September 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 nine 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.

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Regulatory Assets Not Yet Being Recovered

	APCo		I&M	
	September 30, 2010	December 31, 2009	September 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 Implementation Costs	$ -	$ -	$ 6,650 (a)	$ 6,311
Regulatory Assets Currently Not Earning a Return				
Mountaineer Carbon Capture and Storage Project	59,144	110,665	-	-
Virginia Environmental Rate Adjustment Clause	48,141	25,311	-	-
Storm Related Costs	25,225	-	-	-
Deferred Wind Power Costs	23,794	5,372	-	-
Virginia Transmission Rate Adjustment Clause	21,088	26,184	-	-
Special Rate Mechanism for Century Aluminum	12,578	12,422	-	-
Deferred PJM Fees	-	-	7,200	6,254
Total Regulatory Assets Not Yet Being Recovered	$ 189,970	$ 179,954	$ 13,850	$ 12,565

	CSPCo		OPCo	
	September 30, 2010	December 31, 2009	September 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				
Line Extension Carrying Costs	$ 31,915	$ 26,590	$ 19,993	$ 16,278
Customer Choice Deferrals	29,457	28,781	28,906	28,330
Storm Related Costs	18,878	17,014	10,881	9,794
	7,483	10,282	-	-

Acquisition of Monongahela Power				
Economic Development Rider	3,014	-	3,014	-
Regulatory Assets Currently Not Earning a Return				
Acquisition of Monongahela Power	4,052	-	-	-
Peak Demand Reduction/Energy Efficiency	- (b)	4,071	- (b)	4,007
Total Regulatory Assets Not Yet Being Recovered	$ 94,799	$ 86,738	$ 62,794	$ 58,409

	PSO		SWEPCo	
	September 30, 2010	December 31, 2009	September 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	$ 17,256	$ -	$ -	$ -
Asset Retirement Obligation	-	-	588	471
Total Regulatory Assets Not Yet Being Recovered	$ 17,256	$ -	$ 588	$ 471

(a) In October 2010, the Michigan base rate settlement agreement was approved which granted recovery of this regulatory asset.

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

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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. 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 September 30, 2010 were $15 million and $433 million for CSPCo and OPCo, respectively, excluding $2 million and $24 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 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 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 PUCO issues an order on the SEET filings. In September 2010, CSPCo and OPCo filed their 2009 SEET filings with the PUCO. CSPCo's and OPCo's returns on common equity were 20.84% and 10.81%, respectively, including off-system sales margins and 18.31% and 9.42%, respectively, excluding off-system sales margins. Included in the filings was CSPCo's and OPCo's determination that the level at which their earned return on common equity may become significantly in excess of the average earned return on common equity of the comparable risk group of publicly traded firms was 22.51%. Based upon the methodology proposed by CSPCo and OPCo in the SEET filings, neither CSPCo's nor OPCo's 2009 return on common equity was significantly excessive. In October 2010, the PUCO staff filed testimony that recommended a return on common equity over 16.05% as significantly excessive but did not address whether adjustments for off-system sales (OSS) and deferrals should be made to reduce the return. Also, in October 2010, intervenors, including the Ohio Consumers' Counsel, filed testimony with the PUCO recommending an acceptable return on common equity in the range of 11.58% to 13.58%. As a result, the intervenors recommended CSPCo refund up to $156 million of its 2009 earnings. If the PUCO determines that CSPCo's and/or OPCo's 2009 return on common equity was significantly excessive, CSPCo and/or OPCo may be required to return a portion 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.

Proposed CSPCo and OPCo Merger

In October 2010, CSPCo and OPCo filed an application with the PUCO to merge CSPCo into OPCo. Approval of the merger will not affect CSPCo's and OPCo's rates until such time as the PUCO approves new rates, terms and conditions for the merged company. The merger is also subject to regulatory approval by the FERC. CSPCo and OPCo anticipate completion of the merger during 2011.

Requested Sporn Unit 5 Shutdown and Proposed Distribution Rider

In October 2010, OPCo filed an application with the PUCO for the approval of a December 2010 closure of Sporn Unit 5 and the simultaneous establishment of a new non-bypassable distribution rider, outside the rate caps established in the ESP proceeding. The proposed rider would recover the net book value of the unit as well as related materials and supplies as of December 2010, which is estimated to be $59 million, as well as future closure costs incurred after December 2010. OPCo also requested the PUCO to grant accounting authority to record the future closure costs as a regulatory asset or regulatory liability with a weighted average cost of capital carrying charge to be included in the proposed non-bypassable distribution rider after they are incurred. Also in October 2010, OPCo filed a retirement notification with PJM pending PUCO approval of OPCo's application to close Sporn Unit 5. Absent PUCO approval, management intends to operate Sporn Unit 5 through 2013. Management is unable to predict the outcome of this proceeding.

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 or potential other future adjustments 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

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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 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 September 30, 2010, CSPCo and OPCo have incurred $39 million and $30 million, respectively, in EDR costs including carrying costs. Of these costs, CSPCo and OPCo have collected $27 million and $20 million, respectively, through the EDR, which CSPCo and OPCo began collecting in January 2010. The remaining $12 million and $10 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. The carrying costs include both a return of and on the environmental investments as well as related administrative and general expenses and taxes. In August 2010, the PUCO issued an order approving a rider of approximately $26 million and $34 million for CSPCo and OPCo, respectively, effective September 2010. 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 September 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.

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 $132 million for transmission, excluding AFUDC. SWEPCo's share is currently estimated to cost $1.3 billion, excluding AFUDC, plus the additional $132 million for transmission, excluding AFUDC. As of September 30, 2010, excluding costs attributable to its joint owners, SWEPCo has capitalized approximately $957 million of expenditures (including AFUDC and capitalized interest of $121 million and related transmission costs of $58 million). As of September 30, 2010, the joint owners and SWEPCo have contractual construction commitments of approximately $339 million (including related transmission costs of $5 million). SWEPCo's share of the contractual construction commitments is $249 million. If the plant is cancelled, the joint owners and SWEPCo would incur contractual construction cancellation fees, based on construction status as of September 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 significant 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 88 MW 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.

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. The Sierra Club later refiled its petition as a stand alone complaint proceeding. SWEPCo filed a motion to dismiss and denied the allegations in the complaint. In October 2010, an Administrative Law Judge recommended the LPSC dismiss the complaint.

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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, plaintiffs filed with the Federal District Court for the Western District of Arkansas seeking a preliminary injunction to halt construction and for a temporary restraining order.

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 the Interior and the U.S. Fish and Wildlife Service seeking a temporary restraining order and preliminary injunction to stop construction of the Turk Plant asserting claims of violations of federal and state laws. The plaintiffs' federal law claims challenge the process used and terms of the permit issued to SWEPCo authorizing certain wetland and stream impacts. The plaintiffs' state law claims challenge SWEPCo's ability to construct the Turk Plant without obtaining a certificate from the APSC. This motion for preliminary injunction was heard simultaneously with the motion filed by the Sierra Club. In October 2010, the motions for preliminary injunction were partially granted. According to the preliminary injunction, all uncompleted construction work associated with wetlands, streams or rivers at the Turk Plant must immediately stop. Mitigation measures required by the permit are authorized and may be completed. The preliminary injunction affects portions of the water intake and associated piping and portions of the transmission lines. In October 2010, the Federal District Court certified issues relating to the state law claims to the Arkansas Supreme Court, including whether those claims are within the primary jurisdiction of the APSC. The Arkansas Supreme Court has yet to consider the request. SWEPCo filed a notice of appeal with the Federal Court of Appeals for the Eighth Circuit and is seeking a stay of the preliminary injunction pending appeal.

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. A hearing is scheduled for January 2011.

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 September 30, 2010, the Stall Unit cost $423 million, including $49 million of AFUDC. Management does not expect the final costs of the Stall

Unit to exceed the ordered cap. In July 2010, the Stall Unit was placed into Arkansas rates. SWEPCo received CWIP treatment for a portion of the Stall Unit in the 2009 Texas Base Rate Filing. See "2009 Texas Base Rate Filing" section below. The Stall Unit will be phased into Louisiana rate base between October 2010 and October 2011.

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 and that SWEPCo included inappropriate costs in the FAC. In September 2010, the LPSC consultants filed testimony supporting their audit report findings but did not quantify their recommendations. Hearings are scheduled for January 2011. 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 common 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 common 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 AEPEP. Included in this testimony were unquantified refund recommendations relating to re-pricing of contract transactions.

In September 2010, the Administrative Law Judges issued a Proposal for Decision (PFD) that recommended a disallowance of a significant portion of the charges to a ten-year gas transportation agreement that began in 2009 for the Mattison Plant located in Northwest Arkansas. The PFD stated that SWEPCo should have pursued other transportation options or sought the supplier's recourse rate from the FERC. The estimated recommended disallowance over the ten-year period through December 2018 is $107 million for which the estimated Texas jurisdictional portion is $37 million. In addition, the PFD also contained recommendations to disallow risk premiums related to the ERCOT trading contracts transferred to AEPEP which are estimated to be $1.5 million on a Texas retail jurisdictional basis. Through September 30, 2010, SWEPCo's management estimated the impact of this PFD, if adopted by the PUCT, to be $7 million. In October 2010, SWEPCo filed exceptions on these issues with the PUCT. An order may be issued in the fourth quarter of 2010. 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.

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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. 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 common 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 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 which was denied in August 2010. Approximately \$3 million, including interest, was refunded to customers in September 2010 related to the collection of interim rates.

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 September 30, 2010, APCo has recorded a noncurrent regulatory asset of \$59 million related to the Mountaineer Carbon Capture and Storage Project.

In APCo's July 2009 Virginia base rate filing, APCo requested recovery of and a return on its 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. 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 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.

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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 common 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 September 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 September 30, 2010, APCo’s ENEC under-recovery balance was $365 million, excluding $1 million of unrecognized equity 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.

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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 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 AEPEP was filed. Included in this testimony were unquantified refund recommendations relating to re-pricing of contract transactions. A hearing is scheduled for January 2011. 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 common 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 and, 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 net annual increase to ratepayers would be $52 million. The requested increase includes a $24 million increase in depreciation and an 11.5% return on common equity. In October 2010, various parties, including the OCC staff, filed testimony regarding PSO’s requested base rate increase. These parties proposed that PSO's request to increase depreciation rates be denied and that existing depreciation rates continue. PSO’s request to move the $30 million currently recovered through a rider to base rates was not opposed. The parties' net annual rate recommendations ranged from a rate reduction of $18 million to an increase of less than $1 million based on a recommended return on common equity range from 9.5% to 10%. A hearing is scheduled for December 2010.

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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 (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. I&M 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. In October 2010, the Indiana/Michigan Industrial Group and the Indiana Office of Utility Consumer Counselor filed testimony which recommended I&M pay to customers a portion of the accidental outage insurance proceeds up to the extent not previously paid to customers through the fuel adjustment clause or needed to cover costs not covered by I&M's property damage insurance policy. Hearings are scheduled to be held in January 2011.

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 paid to customers, 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 paid to customers, 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. Starting with the August 2010 billing cycle, I&M, with the MPSC authorization, implemented a $44 million interim rate increase. The interim increase excluded new trackers and regulatory assets for which I&M was not currently incurring expenses. In October 2010, a settlement agreement was approved by the MPSC to increase annual base rates by $36 million based on a 10.35% return on common equity, effective December 2010, plus separate recovery of approximately $7 million of customer choice implementation costs over a two year period beginning April 2011. In addition, the approved revenue requirement includes the amortization of $6 million in previously expensed restructuring costs over five years, which I&M will defer and begin amortizing in the fourth quarter of 2010. Also, the approved settlement agreement provided for sharing of off-system sales margins between customers (75%) and I&M (25%) with customers receiving a credit in future Power Supply Cost Recovery proceedings for their jurisdictional share of any off-system sales margins. In September 2010, I&M recorded a provision for refund of $2 million, including interest, related to the implementation of interim rates.

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 request also asked 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 September 30, 2010 was $34 million. APCo's, CSPCo's, I&M's and OPCo's reserve balances at September 30, 2010 were:

Company	September 30, 2010

	(in millions)
APCo	$ 10.7
CSPCo	5.9
I&M	6.3
OPCo	8.1

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In August 2010, the affected companies, including the AEP East companies, filed a compliance filing with the FERC. If the compliance filing is accepted, the AEP East companies would have to pay refunds of approximately $20 million including estimated interest of $5 million. The AEP East companies could also potentially receive payments up to approximately $12 million including estimated interest of $3 million. A decision is pending from the FERC. APCo's, CSPCo's, I&M's and OPCo's portions of potential refund payments and potential payments received are as follows:

Company	Potential Refund Payments	Potential Payments Received
	(in millions)	
APCo	$ 6.4	$ 3.8
CSPCo	3.5	2.1
I&M	3.7	2.2
OPCo	4.8	2.9

Based on the AEP East companies' analysis of the May 2010 order and the compliance filing, management believes that the reserve is adequate to pay the refunds, including interest, that will be required should the May 2010 order or the compliance filing be made final. 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, SWEPCo and FERC customers. 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. In August 2010, a settlement agreement was filed with the FERC. In October 2010, the FERC approved the new TA effective November 1, 2010. The impacts of the settlement agreement will be phased-in for retail rate making purposes in certain jurisdictions over periods of up to four years. However, 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.

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. In October 2010, the settlement agreement was 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 but 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 terminated one of the $1.5 billion facilities that was scheduled to mature in March 2011 and replaced it with a new $1.5 billion credit facility which matures in 2013 and 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 September 30, 2010, $477 million of letters of credit were issued by Registrant Subsidiaries under the agreement to support variable rate Pollution Control Bonds.

At September 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 September 30, 2010, SWEPCo has collected approximately $47 million through a rider for final mine closure and reclamation costs, of which $1 million is recorded in Other Current Liabilities, $23 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $23 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 September 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. Management is currently in negotiations to replace this agreement. 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 September 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	$ 294
CSPCo	70
I&M	181
OPCo	411
PSO	323
SWEPCo	231

Historically, at the end of the lease term the fair value has been in excess of the unamortized balance.

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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 September 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. In October 2010, the Seventh Circuit dismissed all of the remaining claims in these cases. Beckjord is operated by Duke Energy Ohio, Inc.

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.

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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 (TVA). The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The trial court dismissed the lawsuits.

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

In October 2009, the Fifth Circuit Court of Appeals reversed a decision by the Federal District Court for the District of Mississippi dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that CO2 emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs' complaint to a coordinate branch of government and that no initial policy determination was required to adjudicate these claims. The court granted petitions for rehearing. An additional recusal left the Fifth Circuit without a quorum to reconsider the decision and the appeal was dismissed, leaving the district court's decision in place. The Registrant Subsidiaries were initially dismissed from this case without prejudice, but are named as defendants in a pending fourth amended complaint. Plaintiffs filed a petition with the U.S. Supreme Court asking the court to remand the case to the Fifth Circuit and reinstate the panel decision. Responses to the petition are due in November 2010.

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. Briefing is complete and no date has been set for oral argument. 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.

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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 – State and Federal Enforcement Proceedings – Affecting APCo and OPCo

In March 2010, APCo and OPCo received a letter from the West Virginia Department of Environmental Protection, Division of Air Quality (DAQ), alleging that at various times in 2007 through 2009 the units at Amos Plant reported periods of excess opacity (indicator of compliance with particulate matter emission limits) that lasted for more than thirty consecutive minutes in a 24-hour period and that certain required notifications were not made. Management met with representatives of DAQ to discuss these occurrences and the steps taken to prevent a recurrence. DAQ indicated that additional enforcement action may be taken, including imposition of a civil penalty of approximately $240 thousand. APCo and OPCo denied that violations of the reporting requirements occurred and maintain that the proper reporting was done. Management continues to discuss the resolution of these issues with DAQ, but cannot predict the outcome of these discussions or the amount of any penalty that may be assessed.

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 provided additional information to representatives of the Federal EPA. Management has 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 retrofits on two Cardinal Plant units and a Conesville Plant unit are operational. Contracts for other projects were suspended during their early development stages. Due to unexpected operating results, management completed an extensive review in 2009 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. In August 2010, management signed a settlement agreement with Black & Veatch that resolved the issues involving the internal components. Management also reached an agreement in principle regarding JBR vessel corrosion issues. These settlements result in an immaterial increase in the capitalized costs of the projects for modification of the scope of the contracts.

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 September 30, 2010, I&M recorded $53 million on its Condensed Consolidated Balance Sheet representing recoverable amounts under the property insurance policy. Through September 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 review by NEIL includes the timing of the unit’s return to service and whether the return should have occurred earlier reducing the amount received under the accidental outage policy. Intervenors in the Indiana fuel clause proceeding recommend the remaining accidental outage policy revenues should be given to customers through the fuel clause. 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 expired on February 28, 2010. I&M negotiated with Fort Wayne to purchase the assets at the end of the lease, but no agreement was reached prior to the end of the lease. 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 expensing monthly payments made into an escrow account in lieu of rent.

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I&M and Fort Wayne reached a tentative agreement as a result of the mediation process. The agreement was signed on October 28, 2010 and is subject to approval by the Fort Wayne Common Council and the IURC. I&M and Fort Wayne have agreed to cooperate in promptly seeking the requisite approvals. If the agreement is approved, I&M will purchase the remaining leased property and settle claims Fort Wayne asserted. The agreement provides that I&M will pay Fort Wayne a total of $39 million, inclusive of interest, over 15 years and Fort Wayne will recognize that I&M is the exclusive electricity supplier in the Fort Wayne area. I&M will seek recovery in rates of the payments made to Fort Wayne. If the agreement is not approved by the Fort Wayne Common Council and the IURC, the parties have the right to terminate the agreement and pursue other relief.

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. In September 2010, oral arguments were heard by a panel for the U.S. Court of Appeals.

5. ACQUISITION

2010

Valley Electric Membership Corporation – Affecting SWEPCo

In November 2009, SWEPCo signed a letter of intent to purchase certain transmission and distribution assets of Valley Electric Membership Corporation (VEMCO). In October 2010, SWEPCo finalized the purchase for approximately $102 million, subject to working capital and other adjustments, and began serving VEMCO’s 30,000 customers in Louisiana.

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 net periodic benefit cost by Registrant Subsidiary for the plans for the three and nine months ended September 30, 2010 and 2009:

APCo	Pension Plans Three Months Ended September 30,		Other Postretirement Benefit Plans Three Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Service Cost	$ 3,227	$ 3,172	$ 1,431	$ 1,285
Interest Cost	8,489	8,512	5,075	4,928
Expected Return on Plan Assets	(10,952)	(11,222)	(4,407)	(3,383)
Amortization of Transition Obligation	-	-	1,311	1,311
Amortization of Prior Service Cost	229	230	-	-
Amortization of Net Actuarial Loss	2,961	1,922	1,352	1,917
Net Periodic Benefit Cost	$ 3,954	$ 2,614	$ 4,762	$ 6,058

	Pension Plans Nine Months Ended September 30,		Other Postretirement Benefit Plans Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Service Cost	$ 9,681	$ 9,517	$ 4,291	$ 3,857
Interest Cost	25,467	25,537	15,225	14,783
Expected Return on Plan Assets	(32,854)	(33,664)	(13,220)	(10,149)
Amortization of Transition Obligation	-	-	3,933	3,933
Amortization of Prior Service Cost	687	688	-	-
Amortization of Net Actuarial Loss	8,882	5,766	4,057	5,749
Net Periodic Benefit Cost	$ 11,863	$ 7,844	$ 14,286	$ 18,173

CSPCo	Pension Plans Three Months Ended September 30,		Other Postretirement Benefit Plans Three Months Ended September 30,	
	2010	2009	2010	2009

	(in thousands)			
Service Cost	$ 1,469	$ 1,376	$ 690	$ 618
Interest Cost	4,789	4,882	2,178	2,124
Expected Return on Plan Assets	(6,589)	(6,820)	(1,979)	(1,532)
Amortization of Transition Obligation	-	-	608	607
Amortization of Prior Service Cost	141	141	-	-
Amortization of Net Actuarial Loss	1,677	1,108	565	821
Net Periodic Benefit Cost	$ 1,487	$ 687	$ 2,062	$ 2,638

	Pension Plans Nine Months Ended September 30,		Other Postretirement Benefit Plans Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Service Cost	$ 4,405	$ 4,128	$ 2,070	$ 1,853
Interest Cost	14,367	14,647	6,535	6,370
Expected Return on Plan Assets	(19,767)	(20,458)	(5,937)	(4,595)
Amortization of Transition Obligation	-	-	1,824	1,823
Amortization of Prior Service Cost	423	423	-	-
Amortization of Net Actuarial Loss	5,031	3,323	1,695	2,464
Net Periodic Benefit Cost	$ 4,459	$ 2,063	$ 6,187	$ 7,915

I&M

	Pension Plans Three Months Ended September 30,		Other Postretirement Benefit Plans Three Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Service Cost	$ 3,821	$ 3,501	$ 1,688	$ 1,498
Interest Cost	7,271	7,130	3,541	3,419
Expected Return on Plan Assets	(8,759)	(8,934)	(3,350)	(2,565)
Amortization of Transition Obligation	-	-	704	703
Amortization of Prior Service Cost	186	186	-	-
Amortization of Net Actuarial Loss	2,516	1,601	881	1,304
Net Periodic Benefit Cost	$ 5,035	$ 3,484	$ 3,464	$ 4,359

	Pension Plans Nine Months Ended September 30,		Other Postretirement Benefit Plans Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Service Cost	$ 11,463	$ 10,502	$ 5,063	$ 4,493
Interest Cost	21,814	21,390	10,623	10,256
Expected Return on Plan Assets	(26,279)	(26,800)	(10,048)	(7,694)
Amortization of Transition Obligation	-	-	2,111	2,110
Amortization of Prior Service Cost	558	558	-	-
Amortization of Net Actuarial Loss	7,548	4,804	2,644	3,910
Net Periodic Benefit Cost	$ 15,104	$ 10,454	$ 10,393	$ 13,075

OPCo

	Pension Plans Three Months Ended September 30,		Other Postretirement Benefit Plans Three Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Service Cost	$ 2,845	$ 2,759	$ 1,356	$ 1,219
Interest Cost	8,186	8,275	4,446	4,331
Expected Return on Plan Assets	(10,680)	(11,070)	(4,043)	(3,140)

Amortization of Transition Obligation	-	-	1,052	1,053
Amortization of Prior Service Cost	227	228	-	-
Amortization of Net Actuarial Loss	2,861	1,875	1,154	1,676
Net Periodic Benefit Cost	$ 3,439	$ 2,067	$ 3,965	$ 5,139

	Pension Plans Nine Months Ended September 30,		Other Postretirement Benefit Plans Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Service Cost	$ 8,536	$ 8,276	$ 4,069	$ 3,658
Interest Cost	24,558	24,825	13,339	12,994
Expected Return on Plan Assets	(32,040)	(33,208)	(12,132)	(9,420)
Amortization of Transition Obligation	-	-	3,158	3,158
Amortization of Prior Service Cost	681	683	-	-
Amortization of Net Actuarial Loss	8,582	5,625	3,462	5,028
Net Periodic Benefit Cost	$ 10,317	$ 6,201	$ 11,896	$ 15,418

PSO	Pension Plans Three Months Ended September 30,		Other Postretirement Benefit Plans Three Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Service Cost	$ 1,513	$ 1,436	$ 704	$ 631
Interest Cost	3,722	3,842	1,590	1,538
Expected Return on Plan Assets	(4,934)	(5,109)	(1,528)	(1,174)
Amortization of Transition Obligation	-	-	701	701
Amortization of Prior Service Credit	(238)	(270)	-	-
Amortization of Net Actuarial Loss	1,297	871	394	587
Net Periodic Benefit Cost	$ 1,360	$ 770	$ 1,861	$ 2,283

	Pension Plans Nine Months Ended September 30,		Other Postretirement Benefit Plans Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Service Cost	$ 4,539	$ 4,308	$ 2,111	$ 1,892
Interest Cost	11,166	11,526	4,770	4,615
Expected Return on Plan Assets	(14,804)	(15,328)	(4,583)	(3,522)
Amortization of Transition Obligation	-	-	2,104	2,104
Amortization of Prior Service Credit	(713)	(811)	-	-
Amortization of Net Actuarial Loss	3,891	2,615	1,180	1,761
Net Periodic Benefit Cost	$ 4,079	$ 2,310	$ 5,582	$ 6,850

SWEPCo	Pension Plans Three Months Ended September 30,		Other Postretirement Benefit Plans Three Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Service Cost	$ 1,761	$ 1,689	$ 777	$ 704
Interest Cost	3,773	3,889	1,735	1,684
Expected Return on Plan Assets	(4,871)	(5,020)	(1,661)	(1,280)

Amortization of Transition Obligation	-	-	615	615
Amortization of Prior Service Credit	(199)	(229)	-	-
Amortization of Net Actuarial Loss	1,310	879	427	640
Net Periodic Benefit Cost	$ 1,774	$ 1,208	$ 1,893	$ 2,363

	Pension Plans Nine Months Ended September 30,		Other Postretirement Benefit Plans Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Service Cost	$ 5,284	$ 5,067	$ 2,331	$ 2,113
Interest Cost	11,320	11,668	5,205	5,052
Expected Return on Plan Assets	(14,616)	(15,062)	(4,984)	(3,840)
Amortization of Transition Obligation	-	-	1,845	1,845
Amortization of Prior Service Credit	(597)	(687)	-	-
Amortization of Net Actuarial Loss	3,931	2,637	1,283	1,920
Net Periodic Benefit Cost	$ 5,322	$ 3,623	$ 5,680	$ 7,090

The following table provides the actual contributions and payments by Registrant Subsidiary for the pension and OPEB plans during the first nine months of 2010 and the expected contributions and payments for the remainder of 2010:

	Paid as of September 30,		Remainder Expected to be Paid in 2010	
Company	Pension Plans	Other Postretirement Benefit Plans	Pension Plans	Other Postretirement Benefit Plans
		(in thousands)		
APCo	$ 31,979	$ 15,579	$ 4,627	$ 3,067
CSPCo	5,361	6,683	1,565	1,787
I&M	66,733	11,541	4,754	3,549
OPCo	47,222	13,661	4,286	3,068
PSO	11,147	6,133	1,663	2,013
SWEPCo	26,739	6,267	2,294	2,049

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

Trading Strategies

The strategy surrounding the use of derivative instruments for trading purposes focuses on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which AEPSC transacts on behalf of the Registrant Subsidiaries.

Risk Management Strategies

The strategy surrounding the use of derivative instruments focuses on managing risk exposures, future cash flows and creating value 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 power, coal, natural gas, interest rate and to a lesser degree heating oil and 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.

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The following tables represent the gross notional volume of the Registrant Subsidiaries' outstanding derivative contracts as of September 30, 2010 and December 31, 2009:

Notional Volume of Derivative Instruments
September 30, 2010
(in thousands)

Primary Risk Exposure	Unit of Measure	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
Commodity:							
Power	MWHs	237,981	137,187	144,273	167,450	33	57
Coal	Tons	15,365	8,163	6,099	25,606	4,490	8,581
Natural Gas	MMBtus	5,483	3,161	3,297	3,858	81	97
Heating Oil and Gasoline	Gallons	1,361	598	671	1,005	796	733
Interest Rate	USD	$ 11,130	$ 6,394	$ 6,592	$ 8,293	$ 652	$ 899
Interest Rate and Foreign Currency	USD	$ 200,000	$ -	$ -	$ -	$ -	$ 1,319

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

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 power, coal, natural gas and heating oil and gasoline ("Commodity") in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. Management 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 heating oil and gasoline 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 September 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:

	September 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	$	6,306	$	46,860	$	3,789	$	31,806
CSPCo		3,636		27,007		1,920		16,108
I&M		3,792		28,150		1,936		16,222
OPCo		4,438		33,098		2,235		19,512
PSO		-		55		-		194
SWEPCo		-		88		-		305

The following tables represent the gross fair value of the Registrant Subsidiaries' derivative activity on the Condensed Balance Sheets as of September 30, 2010 and December 31, 2009:

Fair Value of Derivative Instruments
September 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	$ 358,539	$ 1,548	$ -	$ (298,888)	$ 61,199
Long-term Risk Management Assets	164,200	14	-	(112,348)	51,866
Total Assets	522,739	1,562	-	(411,236)	113,065
Current Risk Management Liabilities	344,792	4,657	1,216	(322,472)	28,193
Long-term Risk Management Liabilities	149,635	202	-	(133,508)	16,329
Total Liabilities	494,427	4,859	1,216	(455,980)	44,522
Total MTM Derivative Contract Net Assets (Liabilities)	$ 28,312	$ (3,297)	$ (1,216)	$ 44,744	$ 68,543

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
Long-term Risk Management Assets	132,044	-	-	(84,903)	47,141
Total Assets	464,808	3,621	-	(353,332)	115,097
Current Risk Management Liabilities	309,639	5,084	-	(288,931)	25,792
	118,702	80	-	(98,418)	20,364

Long-term Risk Management Liabilities									
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
September 30, 2010

CSPCo

	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	$ 205,558	$ 878	$ -	$ (171,270)	$ 35,166
Long-term Risk Management Assets	94,390	6	-	(64,514)	29,882
Total Assets	299,948	884	-	(235,784)	65,048
Current Risk Management Liabilities	197,685	2,676	-	(184,861)	15,500
Long-term Risk Management Liabilities	85,983	116	-	(76,710)	9,389
Total Liabilities	283,668	2,792	-	(261,571)	24,889
Total MTM Derivative Contract Net Assets (Liabilities)	$ 16,280	$ (1,908)	$ -	$ 25,787	$ 40,159

Fair Value of Derivative Instruments
December 31, 2009

CSPCo

	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	$ 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
September 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	$ 213,839	$ 921	$ -	$ (175,043)	$ 39,717
Long-term Risk Management Assets	107,923	7	-	(66,430)	41,500
Total Assets	321,762	928	-	(241,473)	81,217
Current Risk Management Liabilities	202,473	2,793	-	(189,211)	16,055
Long-term Risk Management Liabilities	88,732	121	-	(79,140)	9,713
Total Liabilities	291,205	2,914	-	(268,351)	25,768
Total MTM Derivative Contract Net Assets (Liabilities)	$ 30,557	$ (1,986)	$ -	$ 26,878	$ 55,449

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
September 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	$ 275,750	$ 1,092	$ -	$ (231,993)	$ 44,849
Long-term Risk Management Assets	121,042	9	-	(84,228)	36,823
Total Assets	396,792	1,101	-	(316,221)	81,672
Current Risk Management Liabilities	267,657	3,278	-	(248,642)	22,293
Long-term Risk Management Liabilities	111,022	143	-	(99,187)	11,978
Total Liabilities	378,679	3,421	-	(347,829)	34,271
Total MTM Derivative Contract Net Assets (Liabilities)	$ 18,113	$ (2,320)	$ -	$ 31,608	$ 47,401

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

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Fair Value of Derivative Instruments
September 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	$ 7,587	$ 65	$ -	$ (4,652)	$ 3,000
Long-term Risk Management Assets	1,604	4	-	(1,107)	501
Total Assets	9,191	69	-	(5,759)	3,501
Current Risk Management Liabilities	4,928	63	-	(4,683)	308
Long-term Risk Management Liabilities	1,228	6	-	(1,115)	119
Total Liabilities	6,156	69	-	(5,798)	427
Total MTM Derivative Contract Net Assets (Liabilities)	$ 3,035	$ -	$ -	$ 39	$ 3,074

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
Current Risk Management Liabilities	14,981	301	-	(12,703)	2,579

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
September 30, 2010

SWEPCo

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	$ 12,973	$ 48	$ 2	$ (11,006)	$ 2,017
Long-term Risk Management Assets	3,027	3	6	(2,617)	419
Total Assets	16,000	51	8	(13,623)	2,436
Current Risk Management Liabilities	11,431	37	87	(11,032)	523
Long-term Risk Management Liabilities	2,926	6	-	(2,660)	272
Total Liabilities	14,357	43	87	(13,692)	795
Total MTM Derivative Contract Net Assets (Liabilities)	$ 1,643	$ 8	$ (79)	$ 69	$ 1,641

Fair Value of Derivative Instruments
December 31, 2009

SWEPCo

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	$ 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.

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The tables below presents the Registrant Subsidiaries' activity of derivative risk management contracts for the three and nine months ended September 30, 2010 and 2009:

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

Location of Gain (Loss)	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Electric Generation, Transmission and Distribution Revenues	$ 1,938	$ 6,436	$ 6,374	$ 5,378	$ 686	$ 1,123
Sales to AEP Affiliates	(522)	(704)	(571)	2,605	(204)	(486)
Regulatory Assets (a)	-	(2,013)	-	(4,064)	16	-
Regulatory Liabilities (a)	4,538	-	1,956	-	999	893
Total Gain (Loss) on Risk Management Contracts	$ 5,954	$ 3,719	$ 7,759	$ 3,919	$ 1,497	$ 1,530

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

Location of Gain (Loss)	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Electric Generation, Transmission and Distribution Revenues	$ 2,240	$ 6,551	$ 7,127	$ 3,155	$ (850)	$ (1,067)
Sales to AEP Affiliates	(237)	(238)	(292)	302	1,135	1,347
Regulatory Assets (a)	-	(2,616)	(1,278)	(2,922)	(617)	(20)
Regulatory Liabilities (a)	10,199	4,774	3,369	5,384	(480)	9
Total Gain (Loss) on Risk Management Contracts	$ 12,202	$ 8,471	$ 8,926	$ 5,919	$ (812)	$ 269

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Nine Months Ended September 30, 2010

Location of Gain (Loss)	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Electric Generation, Transmission and Distribution Revenues	$ 4,419	$ 19,513	$ 15,762	$ 17,609	$ 1,716	$ 2,524
Sales to AEP Affiliates	(2,098)	(2,153)	(1,913)	5,014	(502)	(1,024)
Regulatory Assets (a)	-	(3,557)	-	(5,725)	321	73
Regulatory Liabilities (a)	19,686	-	10,418	-	3,763	1,406
Total Gain (Loss) on Risk Management Contracts	$ 22,007	$ 13,803	$ 24,267	$ 16,898	$ 5,298	$ 2,979

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Nine Months Ended September 30, 2009

Location of Gain (Loss)	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Electric Generation, Transmission and Distribution Revenues	$ 13,211	$ 26,557	$ 31,333	$ 27,453	$ (2)	$ 151
Sales to AEP Affiliates	(7,563)	(4,707)	(4,710)	(1,191)	510	372
Regulatory Assets (a)	-	(6,243)	(3,727)	(7,231)	(283)	200
Regulatory Liabilities (a)	24,479	2,284	4,347	2,300	(1,696)	(65)
Total Gain (Loss) on Risk Management Contracts	$ 30,127	$ 17,891	$ 27,243	$ 21,331	$ (1,471)	$ 658

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

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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 nine months ended September 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 power, coal, natural gas, and heating oil and gasoline 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 nine months ended September 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 nine months ended September 30, 2010, the Registrant Subsidiaries designated cash flow hedging strategies of forecasted fuel purchases.

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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 nine months ended September 30, 2010, APCo designated interest rate derivatives as cash flow hedges. During the three and nine months ended September 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 nine months ended September 30, 2010 and 2009, SWEPCo designated foreign currency derivatives as cash flow hedges.

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

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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 nine months ended September 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 September 30, 2010

Commodity Contracts	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Balance in AOCI as of June 30, 2010	$ (1,437)	$ (807)	$ (813)	$ (941)	$ (84)	$ (33)
Changes in Fair Value Recognized in AOCI	(1,212)	(729)	(776)	(914)	69	60
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:						
Electric Generation, Transmission, and Distribution Revenues	60	159	127	184	-	-
Fuel and Other Consumables Used for Electric Generation	-	-	-	-	40	-
Purchased Electricity for Resale	56	156	138	195	-	-
Other Operation Expense	(7)	(5)	(5)	(6)	(7)	(7)
Maintenance Expense	(11)	(3)	(5)	(6)	(4)	(3)
Property, Plant and Equipment	(11)	(4)	(5)	(9)	(7)	(5)
Regulatory Assets (a)	436	-	58	-	-	-
Regulatory Liabilities (a)	-	-	-	-	-	-
Balance in AOCI as of September 30, 2010	$ (2,126)	$ (1,233)	$ (1,281)	$ (1,497)	$ 7	$ 12

Interest Rate and Foreign Currency Contracts	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Balance in AOCI as of June 30, 2010	$ (8,298)	$ -	$ (9,011)	$ 11,492	$ (443)	$ (4,812)
Changes in Fair Value Recognized in AOCI	(790)	-	-	1	-	122
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:						
Depreciation and Amortization Expense	-	-	-	1	-	-
Other Operation Expense	-	-	-	-	-	(3)

Interest Expense		394		-		252		(341)		18		207
Balance in AOCI as of September 30, 2010	$	(8,694)	$	-	$	(8,759)	$	11,153	$	(425)	$	(4,486)

Total Contracts		APCo		CSPCo		I&M		OPCo		PSO		SWEPCo
						(in thousands)						
Balance in AOCI as of June 30, 2010	$	(9,735)	$	(807)	$	(9,824)	$	10,551	$	(527)	$	(4,845)
Changes in Fair Value Recognized in AOCI		(2,002)		(729)		(776)		(913)		69		182
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:												
Electric Generation, Transmission, and Distribution Revenues		60		159		127		184		-		-
Fuel and Other Consumables Used for Electric Generation		-		-		-		-		40		-
Purchased Electricity for Resale		56		156		138		195		-		-
Other Operation Expense		(7)		(5)		(5)		(6)		(7)		(10)
Maintenance Expense		(11)		(3)		(5)		(6)		(4)		(3)
Depreciation and Amortization Expense		-		-		-		1		-		-
Interest Expense		394		-		252		(341)		18		207
Property, Plant and Equipment		(11)		(4)		(5)		(9)		(7)		(5)
Regulatory Assets (a)		436		-		58		-		-		-
Regulatory Liabilities (a)		-		-		-		-		-		-
Balance in AOCI as of September 30, 2010	$	(10,820)	$	(1,233)	$	(10,040)	$	9,656	$	(418)	$	(4,474)

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

Commodity Contracts	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Balance in AOCI as of June 30, 2009	$ 2,296	$ 1,189	$ 1,170	$ 1,526	$ 127	$ 141
Changes in Fair Value Recognized in AOCI	(451)	(232)	(227)	(346)	(377)	(45)
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:						
Electric Generation, Transmission, and Distribution Revenues	(720)	(1,815)	(1,385)	(2,126)	-	-
Fuel and Other Consumables Used for Electric Generation	(39)	(17)	(20)	(27)	(20)	(22)
Purchased Electricity for Resale	444	1,116	852	1,313	-	-
Other Operation Expense	-	-	-	-	-	-
Maintenance Expense	-	-	-	-	-	-
Property, Plant and Equipment	(23)	(9)	(12)	(17)	(12)	(9)
Regulatory Assets (a)	1,664	-	226	-	-	-
Regulatory Liabilities (a)	(2,709)	-	(369)	-	-	-
Balance in AOCI as of September 30, 2009	$ 462	$ 232	$ 235	$ 323	$ (282)	$ 65

Interest Rate and Foreign Currency Contracts	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Balance in AOCI as of June 30, 2009	$ (7,285)	$ -	$ (10,017)	$ 16,662	$ (613)	$ (5,497)
Changes in Fair Value Recognized in AOCI	-	-	-	(4,038)	-	82
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:						
Depreciation and Amortization Expense	-	-	(2)	1	-	-
Interest Expense	418	-	253	(113)	46	208
Balance in AOCI as of September 30, 2009	$ (6,867)	$ -	$ (9,766)	$ 12,512	$ (567)	$ (5,207)

Total Contracts	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo

					(in thousands)							
Balance in AOCI as of June 30, 2009	$	(4,989)	$	1,189	$	(8,847)	$	18,188	$	(486)	$	(5,356)
Changes in Fair Value Recognized in AOCI		(451)		(232)		(227)		(4,384)		(377)		37
Amount of (Gain) or Loss Reclassified												
from AOCI to Income Statement/within												
Balance Sheet:												
Electric Generation, Transmission, and												
Distribution Revenues		(720)		(1,815)		(1,385)		(2,126)		-		-
Fuel and Other Consumables Used for												
Electric Generation		(39)		(17)		(20)		(27)		(20)		(22)
Purchased Electricity for Resale		444		1,116		852		1,313		-		-
Other Operation Expense		-		-		-		-		-		-
Maintenance Expense		-		-		-		-		-		-
Depreciation and Amortization												
Expense		-		-		(2)		1		-		-
Interest Expense		418		-		253		(113)		46		208
Property, Plant and Equipment		(23)		(9)		(12)		(17)		(12)		(9)
Regulatory Assets (a)		1,664		-		226		-		-		-
Regulatory Liabilities (a)		(2,709)		-		(369)		-		-		-
Balance in AOCI as of September 30, 2009	$	(6,405)	$	232	$	(9,531)	$	12,835	$	(849)	$	(5,142)

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Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Nine Months Ended September 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	(3,069)	(1,806)	(1,859)	(2,214)	(36)	(36)
Amount of (Gain) or Loss Reclassified						
from AOCI to Income Statement/within						
Balance Sheet:						
Electric Generation, Transmission, and						
Distribution Revenues	117	303	247	351	-	-
Fuel and Other Consumables Used for						
Electric Generation	-	-	-	(13)	190	-
Purchased Electricity for Resale	267	706	593	828	-	-
Other Operation Expense	(31)	(24)	(22)	(26)	(26)	(30)
Maintenance Expense	(47)	(15)	(19)	(21)	(16)	(15)
Property, Plant and Equipment	(44)	(21)	(22)	(31)	(27)	(19)
Regulatory Assets (a)	1,424	-	183	-	-	-
Regulatory Liabilities (a)	-	-	-	(5)	-	-
Balance in AOCI as of September 30, 2010	$ (2,126)	$ (1,233)	$ (1,281)	$ (1,497)	$ 7	$ 12

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	(3,475)	-	-	1	-	(81)
Amount of (Gain) or Loss Reclassified						
from AOCI to Income Statement/within						
Balance Sheet:						
Depreciation and Amortization						
Expense	-	-	-	3	-	-
Other Operation Expense	-	-	-	-	-	21
Interest Expense	1,231	-	755	(1,023)	96	621

	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
Balance in AOCI as of September 30, 2010	$ (8,694)	$ -	$ (8,759)	$ 11,153	$ (425)	$ (4,486)

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	(6,544)	(1,806)	(1,859)	(2,213)	(36)	(117)
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:						
Electric Generation, Transmission, and Distribution Revenues	117	303	247	351	-	-
Fuel and Other Consumables Used for Electric Generation	-	-	-	(13)	190	-
Purchased Electricity for Resale	267	706	593	828	-	-
Other Operation Expense	(31)	(24)	(22)	(26)	(26)	(9)
Maintenance Expense	(47)	(15)	(19)	(21)	(16)	(15)
Depreciation and Amortization Expense	-	-	-	3	-	-
Interest Expense	1,231	-	755	(1,023)	96	621
Property, Plant and Equipment	(44)	(21)	(22)	(31)	(27)	(19)
Regulatory Assets (a)	1,424	-	183	-	-	-
Regulatory Liabilities (a)	-	-	-	(5)	-	-
Balance in AOCI as of September 30, 2010	$ (10,820)	$ (1,233)	$ (10,040)	$ 9,656	$ (418)	$ (4,474)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Nine Months Ended September 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	(278)	(257)	(233)	(325)	(246)	100
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:						
Electric Generation, Transmission, and Distribution Revenues	(1,429)	(3,586)	(2,774)	(4,319)	-	-
Fuel and Other Consumables Used for Electric Generation	(45)	(21)	(24)	(32)	(23)	(25)
Purchased Electricity for Resale	1,038	2,576	2,033	3,120	-	-
Other Operation Expense	-	-	-	-	-	-
Maintenance Expense	-	-	-	-	-	-
Property, Plant and Equipment	(26)	(11)	(13)	(19)	(13)	(10)
Regulatory Assets (a)	3,800	-	457	-	-	-
Regulatory Liabilities (a)	(5,324)	-	(693)	-	-	-
Balance in AOCI as of September 30, 2009	$ 462	$ 232	$ 235	$ 323	$ (282)	$ 65

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	-	-	-	10,915	-	95
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:						
Depreciation and Amortization Expense	-	-	(4)	3	-	-
Interest Expense	1,251	-	759	(158)	137	622
Balance in AOCI as of September 30, 2009	$ (6,867)	$ -	$ (9,766)	$ 12,512	$ (567)	$ (5,207)

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	(278)	(257)	(233)	10,590	(246)	195
Amount of (Gain) or Loss Reclassified						
from AOCI to Income Statement/within						
Balance Sheet:						
Electric Generation, Transmission, and						
Distribution Revenues	(1,429)	(3,586)	(2,774)	(4,319)	-	-
Fuel and Other Consumables Used for						
Electric Generation	(45)	(21)	(24)	(32)	(23)	(25)
Purchased Electricity for Resale	1,038	2,576	2,033	3,120	-	-
Other Operation Expense	-	-	-	-	-	-
Maintenance Expense	-	-	-	-	-	-
Depreciation and Amortization						
Expense	-	-	(4)	3	-	-
Interest Expense	1,251	-	759	(158)	137	622
Property, Plant and Equipment	(26)	(11)	(13)	(19)	(13)	(10)
Regulatory Assets (a)	3,800	-	457	-	-	-
Regulatory Liabilities (a)	(5,324)	-	(693)	-	-	-
Balance in AOCI as of September 30, 2009	$ (6,405)	$ 232	$ (9,531)	$ 12,835	$ (849)	$ (5,142)

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

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

Impact of Cash Flow Hedges on the Registrant Subsidiaries' Condensed Balance Sheets
September 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	$ 70	$ -	$ (3,367)	$ (1,216)	$ (2,126)	$ (8,694)
CSPCo	32	-	(1,940)	-	(1,233)	-
I&M	37	-	(2,023)	-	(1,281)	(8,759)
OPCo	50	-	(2,370)	-	(1,497)	11,153
PSO	21	-	(21)	-	7	(425)
SWEPCo	19	8	(11)	(87)	12	(4,486)

	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	$ (2,002)	$ (1,733)	15
CSPCo	(1,161)	-	15
I&M	(1,208)	(1,007)	15
OPCo	(1,410)	1,359	15
PSO	9	(73)	15
SWEPCo	13	(829)	26

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, Standard and Poor's and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

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 September 30, 2010 and December 31, 2009:

September 30, 2010

Company	Liabilities for Derivative Contracts with Credit Downgrade Triggers	Amount of Collateral the Registrant Subsidiaries Would Have Been Required to Post	Amount Attributable to RTO and ISO Activities
		(in thousands)	
APCo	$ 7,600	$ 9,459	$ 9,261
CSPCo	4,381	5,453	5,339
I&M	4,570	5,688	5,569
OPCo	5,347	6,656	6,517
PSO	10	1,809	1,694
SWEPCo	12	2,167	2,029

As of September 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	Amount Attributable to RTO and ISO Activities
		(in thousands)	
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.

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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 does not anticipate a non-performance event under these provisions. 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 September 30, 2010 and December 31, 2009:

September 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	$ 128,044	$ 19,328	$ 30,372
CSPCo	73,111	11,142	16,807
I&M	76,260	11,622	17,528
OPCo	89,264	13,600	20,540
PSO	117	-	40
SWEPCo	233	-	133

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 September 30, 2010 and December 31, 2009 are summarized in the following table:

	September 30, 2010		December 31, 2009	
Company	Book Value	Fair Value	Book Value	Fair Value
		(in thousands)		
APCo	$ 3,560,959	$ 4,075,531	$ 3,477,306	$ 3,699,373
CSPCo	1,588,753	1,791,795	1,536,393	1,616,857
I&M	2,118,911	2,399,239	2,077,906	2,192,854
OPCo	2,929,386	3,249,304	3,242,505	3,380,084
PSO	970,643	1,095,500	968,121	1,007,183
SWEPCo	1,769,457	2,050,992	1,474,153	1,554,165

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

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

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

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

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

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

	September 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	$ 30,217	$ -	$ -	$ 14,412	$ -	$ -
Fixed Income Securities:						
United States Government	489,026	40,901	(1,036)	400,565	12,708	(3,472)
Corporate Debt	64,744	5,039	(1,988)	57,291	4,636	(2,177)
State and Local Government	307,660	(6,991)	(527)	368,930	7,924	991
Subtotal Fixed Income Securities	861,430	38,949	(3,551)	826,786	25,268	(4,658)
Equity Securities - Domestic	574,052	124,051	(122,769)	550,721	234,437	(119,379)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,465,699	$ 163,000	$ (126,320)	$ 1,391,919	$ 259,705	$ (124,037)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in thousands)			
Proceeds From Investment Sales	$ 495,221	$ 112,900	$ 1,087,484	$ 523,927
Purchases of Investments	511,688	129,239	1,128,747	571,167
Gross Realized Gains on Investment Sales	1,168	1,137	7,518	10,490
Gross Realized Losses on Investment Sales	33	196	450	1,004

The adjusted cost of debt securities was $823 million and $801 million as of September 30, 2010 and December 31, 2009, respectively.

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

	Fair Value of Debt Securities (in thousands)
Within 1 year	$ 13,134
1 year – 5 years	346,079
5 years – 10 years	266,801
After 10 years	235,416

Total	$	861,430

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 September 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
September 30, 2010

APCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (g)	$ 2,786	$ 489,714	$ 27,711	$ (412,038)	$ 108,173
Cash Flow Hedges:					
Commodity Hedges (a)	-	1,548	-	(1,478)	70
Dedesignated Risk Management Contracts (b)	-	-	-	4,822	4,822
Total Risk Management Assets	$ 2,786	$ 491,262	$ 27,711	$ (408,694)	$ 113,065
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (g)	$ 2,725	$ 478,028	$ 11,146	$ (452,592)	$ 39,307
Cash Flow Hedges:					
Commodity Hedges (a)	-	4,845	-	(1,478)	3,367
Interest Rate/Foreign Currency Hedges	-	1,216	-	-	1,216
DETM Assignment (c)	-	-	-	632	632
Total Risk Management Liabilities	$ 2,725	$ 484,089	$ 11,146	$ (453,438)	$ 44,522

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					
	$ 2,648	$ 422,063	$ 3,438	$ (388,265)	$ 39,884

Risk Management Commodity Contracts (a)					
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

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

CSPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (g)	$ 1,606	$ 280,931	$ 15,972	$ (236,273)	$ 62,236
Cash Flow Hedges:					
Commodity Hedges (a)	-	876	-	(844)	32
Dedesignated Risk Management Contracts (b)	-	-	-	2,780	2,780
Total Risk Management Assets	$ 1,606	$ 281,807	$ 15,972	$ (234,337)	$ 65,048
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (g)	$ 1,571	$ 274,233	$ 6,425	$ (259,644)	$ 22,585
Cash Flow Hedges:					
Commodity Hedges (a)	-	2,784	-	(844)	1,940
DETM Assignment (c)	-	-	-	364	364
Total Risk Management Liabilities	$ 1,571	$ 277,017	$ 6,425	$ (260,124)	$ 24,889

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
September 30, 2010

I&M

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (g)	$ 1,676	$ 301,988	$ 16,655	$ (242,039)	$ 78,280
Cash Flow Hedges:					
Commodity Hedges (a)	-	919	-	(882)	37
Dedesignated Risk Management Contracts (b)	-	-	-	2,900	2,900
Total Risk Management Assets	1,676	302,907	16,655	(240,021)	81,217
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	-	20,776	-	9,441	30,217
Fixed Income Securities:					
United States Government	-	489,026	-	-	489,026
Corporate Debt	-	64,744	-	-	64,744
State and Local Government	-	307,660	-	-	307,660
Subtotal Fixed Income Securities	-	861,430	-	-	861,430
Equity Securities - Domestic (f)	574,052	-	-	-	574,052
Total Spent Nuclear Fuel and Decommissioning Trusts	574,052	882,206	-	9,441	1,465,699
Total Assets	$ 575,728	$ 1,185,113	$ 16,655	$ (230,580)	$ 1,546,916
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (g)	$ 1,639	$ 281,426	$ 6,697	$ (266,397)	$ 23,365
Cash Flow Hedges:					
Commodity Hedges (a)	-	2,905	-	(882)	2,023
DETM Assignment (c)	-	-	-	380	380
Total Risk Management Liabilities	$ 1,639	$ 284,331	$ 6,697	$ (266,899)	$ 25,768

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

I&M

Assets:	Level 1	Level 2	Level 3 (in thousands)	Other	Total
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
September 30, 2010

OPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Other Cash Deposits (d)	$ 26	$ -	$ -	$ -	$ 26
Risk Management Assets					
Risk Management Commodity Contracts (a) (g)	1,961	373,224	19,540	(316,496)	78,229
Cash Flow Hedges:					
Commodity Hedges (a)	-	1,092	-	(1,042)	50
Dedesignated Risk Management Contracts (b)	-	-	-	3,393	3,393
Total Risk Management Assets	1,961	374,316	19,540	(314,145)	81,672
Total Assets	$ 1,987	$ 374,316	$ 19,540	$ (314,145)	$ 81,698
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (g)	$ 1,917	$ 366,812	$ 7,883	$ (345,156)	$ 31,456
Cash Flow Hedges:					
Commodity Hedges (a)	-	3,412	-	(1,042)	2,370
DETM Assignment (c)	-	-	-	445	445
Total Risk Management Liabilities	$ 1,917	$ 370,224	$ 7,883	$ (345,753)	$ 34,271

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
September 30, 2010

PSO

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (g)	$ 9	$ 9,098	$ 11	$ (5,638)	$ 3,480
Cash Flow Hedges:					
Commodity Hedges (a)	-	69	-	(48)	21
Total Risk Management Assets	$ 9	$ 9,167	$ 11	$ (5,686)	$ 3,501
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (g)	$ 8	$ 6,066	$ 9	$ (5,693)	$ 390
Cash Flow Hedges:					
Commodity Hedges (a)	-	69	-	(48)	21
DETM Assignment (c)	-	-	-	16	16
Total Risk Management Liabilities	$ 8	$ 6,135	$ 9	$ (5,725)	$ 427

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
September 30, 2010

SWEPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (g)	$ 11	$ 15,793	$ 21	$ (13,416)	$ 2,409
Cash Flow Hedges:					
Commodity Hedges (a)	-	51	-	(32)	19
Interest Rate/Foreign Currency Hedges (a)	-	8	-	-	8
Total Risk Management Assets	$ 11	$ 15,852	$ 21	$ (13,448)	$ 2,436
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (g)	$ 10	$ 14,153	$ 19	$ (13,504)	$ 678
Cash Flow Hedges:					
Commodity Hedges (a)	-	43	-	(32)	11
Interest Rate/Foreign Currency Hedges (a)	-	87	-	-	87
DETM Assignment (c)	-	-	-	19	19
Total Risk Management Liabilities	$ 10	$ 14,283	$ 19	$ (13,517)	$ 795

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 nine months ended September 30, 2010.

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

Three Months Ended September 30, 2010	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Balance as of June 30, 2010	$ 10,874	$ 6,153	$ 6,209	$ 7,069	$ (2)	$ (2)
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(1,680)	(845)	(850)	(981)	2	2
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-	5,941	-	9,258	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-	-	-	-
Purchases, Issuances and Settlements (c)	195	118	133	157	2	3
Transfers into Level 3 (d) (h)	380	215	217	247	-	-
Transfers out of Level 3 (e) (h)	(890)	(503)	(508)	(579)	(1)	(2)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	7,686	(1,532)	4,757	(3,514)	1	1
Balance as of September 30, 2010	$ 16,565	$ 9,547	$ 9,958	$ 11,657	$ 2	$ 2

Nine Months Ended September 30, 2010	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
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)	1,269	713	721	825	1	3
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-	10,670	-	14,651	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-	-	-	-
Purchases, Issuances and Settlements (c)	(5,463)	(3,059)	(3,100)	(3,565)	(1)	(2)

Transfers into Level 3 (d) (h)		986		530		528		615		-		-
Transfers out of Level 3 (e) (h)		(2,088)		(1,195)		(1,199)		(1,376)		-		-
Changes in Fair Value Allocated to Regulated Jurisdictions (g)		12,433		(2,888)		8,192		(5,062)		-		(2)
Balance as of September 30, 2010	$	16,565	$	9,547	$	9,958	$	11,657	$	2	$	2

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Three Months Ended September 30, 2009	APCo	CSPCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Balance as of June 30, 2009	$ 13,900	$ 7,372	$ 7,135	$ 9,410	$ 12	$ 15
Realized (Gain) Loss Included in Net Income						
(or Changes in Net Assets) (a)	(2,762)	(1,465)	(1,418)	(2,087)	(11)	(13)
Unrealized Gain (Loss) Included in Net						
Income (or Changes in Net Assets) Relating						
to Assets Still Held at the Reporting Date (a)	-	347	-	(185)	-	-
Realized and Unrealized Gains (Losses)						
Included in Other Comprehensive Income	-	-	-	-	-	-
Purchases, Issuances and Settlements	-	-	-	-	-	-
Transfers in and/or out of Level 3 (f)	2,322	1,231	1,192	1,525	-	-
Changes in Fair Value Allocated to Regulated						
Jurisdictions (g)	10,188	5,047	5,176	5,723	4	4
Balance as of September 30, 2009	$ 23,648	$ 12,532	$ 12,085	$ 14,386	$ 5	$ 6

Nine Months Ended September 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)	(6,448)	(3,621)	(3,504)	(4,473)	3	5
Unrealized Gain (Loss) Included in Net						
Income (or Changes in Net Assets) Relating						
to Assets Still Held at the Reporting Date (a)	-	6,069	-	6,906	-	-
Realized and Unrealized Gains (Losses)						
Included in Other Comprehensive Income	-	-	-	-	-	-
Purchases, Issuances and Settlements	-	-	-	-	-	-
Transfers in and/or out of Level 3 (f)	(328)	(184)	(178)	(228)	-	-
Changes in Fair Value Allocated to Regulated						
Jurisdictions (g)	22,415	5,771	11,415	6,618	4	4
Balance as of September 30, 2009	$ 23,648	$ 12,532	$ 12,085	$ 14,386	$ 5	$ 6

(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 nine months ended September 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	-

The Small Business Jobs Act was enacted in September 2010. Included in this act was a one-year extension of the 50% bonus depreciation provision. The enacted provision will not have a material impact on the Registrant Subsidiaries' net income or financial condition but will have a material favorable impact on cash flows.

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11. FINANCING ACTIVITIES

Long-term Debt

Long-term debt and other securities issued, retired and principal payments made during the first nine 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
OPCo	Pollution Control Bonds	39,130	2.875	2014
SWEPCo	Senior Unsecured Notes	350,000	6.20	2040
SWEPCo	Pollution Control Bonds	53,500	3.25	2015
PSO	Notes Payable	1,750	3.00	2025

Company	Type of Debt	Principal Amount Paid (in thousands)	Interest Rate (%)	Due Date
Retirements and Principal Payments:				
APCo	Land Note	$ 14	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
OPCo	Pollution Control Bonds	19,565	5.625	2022
OPCo	Pollution Control Bonds	19,565	5.625	2023
SWEPCo	Notes Payable - Affiliated	50,000	4.45	2010
SWEPCo	Pollution Control Bonds	53,500	Variable	2019

In October 2010, I&M retired $150 million of 6% Senior Unsecured Notes due in 2032.

In November 2010, OPCo retired $200 million of 5.3% Senior Unsecured Notes due in 2010.

On behalf of OPCo, trustees held $303 million of reacquired auction-rate tax-exempt long-term debt as of September 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.

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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%.

At September 30, 2010, approximately $111 million of the retained earnings of APCo, $148 million of the retained earnings of CSPCo, $29 million of the retained earnings of I&M, $49 million of the retained earnings of OPCo, $100 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 September 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 nine months ended September 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 (Borrowings) to/from Utility Money Pool as of September 30, 2010	Authorized Short-term Borrowing Limit
			(in thousands)			
APCo	$ 438,039	$ -	$ 275,422	$ -	$ (55,113)	$ 600,000
CSPCo	134,592	201,486	32,368	71,571	182,225	350,000
I&M	-	223,111	-	110,696	192,779	500,000
OPCo	-	618,559	-	256,426	290,714	600,000
PSO	107,320	74,751	50,927	41,836	(23,024)	300,000
SWEPCo	78,616	274,958	39,458	218,555	213,689	350,000

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool were as follows:

	Nine Months Ended September 30,			
	2010		2009	
Maximum Interest Rate	0.55	%	2.28	%
Minimum Interest Rate	0.09	%	0.27	%

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The average interest rates for funds borrowed from and loaned to the Utility Money Pool for the nine months ended September 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 Nine Months Ended September 30, 2010	2009	Average Interest Rate for Funds Loaned to the Utility Money Pool for the Nine Months Ended September 30, 2010	2009
APCo	0.25 %	1.14 %	- %	- %
CSPCo	0.18 %	1.13 %	0.27 %	0.57 %
I&M	- %	1.46 %	0.24 %	0.49 %
OPCo	- %	1.21 %	0.20 %	0.38 %
PSO	0.29 %	2.01 %	0.16 %	1.04 %
SWEPCo	0.19 %	1.66 %	0.27 %	0.77 %

Short-term Debt

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

Company	Type of Debt	September 30, 2010 Outstanding Amount (in thousands)	September 30, 2010 Interest Rate (b)	December 31, 2009 Outstanding Amount (in thousands)	December 31, 2009 Interest Rate (b)
SWEPCo	Line of Credit – Sabine (a)	$ 3,170	2.20 %	$ 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 terminated one of the $1.5 billion facilities that was scheduled to mature in March 2011 and replaced it with a new $1.5 billion credit facility which matures in 2013 and allows for the issuance of up to $600 million as letters of credit. As of September 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 September 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 Subsidiary's 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 expense 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 September 30, 2010 and December 31, 2009 was as follows:

Company	September 30, 2010	December 31, 2009
	(in thousands)	
APCo	$ 142,747	$ 143,938
CSPCo	196,949	169,095
I&M	138,134	130,193
OPCo	168,306	160,977
PSO	161,179	73,518
SWEPCo	169,235	117,297

The fees paid by the Registrant Subsidiaries to AEP Credit for customer accounts receivable sold were:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Company	2010	2009	2010	2009
	(in thousands)			
APCo	$ 2,949	$ 1,186	$ 6,725	$ 3,711
CSPCo	3,300	2,956	8,990	8,481
I&M	1,832	1,617	5,276	4,507
OPCo	2,345	2,340	7,494	6,351
PSO	1,537	1,738	4,287	5,397
SWEPCo	1,441	1,747	4,574	4,569

The Registrant Subsidiaries' proceeds on the sale of receivables to AEP Credit were:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Company	2010	2009	2010	2009
	(in thousands)			
APCo	$ 338,446	$ 298,997	$ 1,097,276	$ 923,408
CSPCo	521,030	442,079	1,368,343	1,243,325
I&M	348,039	319,932	984,631	908,007
OPCo	473,773	394,335	1,325,613	1,184,744
PSO	398,177	265,622	924,707	812,264
SWEPCo	430,270	373,805	1,087,515	1,009,124

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 across the AEP System 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	Adjustments	Remaining Balance at September 30, 2010
			(in thousands)		
APCo	$ 20,526	$ 36,399	$ 48,431	$ (3,621)	$ 4,873
CSPCo	11,048	21,244	28,542	(557)	3,193
I&M	12,051	32,985	39,192	(2,135)	3,709
OPCo	19,427	33,681	50,923	2,175	4,360
PSO	10,681	13,324	20,908	(651)	2,446
SWEPCo	12,588	17,074	26,430	(522)	2,710

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.

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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 6% in the third quarter and 5% during the first nine 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.

Capital Expenditures

In October 2010, management announced capital expenditures budgets by Registrant Subsidiaries for 2011 as follows:

Company	Budgeted Construction Expenditures (in millions)
APCo	$ 466
CSPCo	178
I&M	307
OPCo	271
PSO	171
SWEPCo	457

ENVIRONMENTAL ISSUES

The Registrant Subsidiaries are implementing a substantial capital investment program and incurring additional operational costs to comply with new environmental control requirements. The Registrant Subsidiaries will need to make additional investments and operational changes in response to existing and anticipated requirements such as 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 SNF and future decommissioning of I&M's nuclear units. Management is also involved in development of possible future requirements including the items discussed below and reductions of CO_2 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, decrease reliability and unfavorably impact financial condition if the increased costs are suspended during the early development stages not recovered in rates or market prices. Comments on the proposed rule were due on October 1, 2010. The AEP System's comments pointed out the inaccuracies of some of the assumptions used by the Federal EPA, the flawed nature of its modeling analysis and unreasonable time frame for implementing the rule. Management believes that the Federal EPA made erroneous assumptions about the existence and/or capabilities of current control equipment at certain of the AEP System's units, used timeframes for installation of new controls that are inconsistent with recent experience and made questionable assumptions regarding the ability to switch fuel supplies at existing units. A notice of additional information was issued and comments on that package were accepted until October 15, 2010. The proposal indicates that the requirements are expected to be finalized in June 2011 and become effective January 1, 2012.

Mercury and Other Hazardous Air Pollutants (HAPs) Regulation

The Federal EPA issued the Clean Air Mercury Rule (CAMR) in 2005, setting mercury emission standards for new coal-fired power plants and requiring all states to issue new state implementation plans including mercury requirements for existing coal-fired power plants. The CAMR was vacated and remanded to the Federal EPA by the D.C. Circuit Court of Appeals in 2008. The Federal EPA issued an information collection request to owners and operators of existing power plants in 2010 to collect information to support the development of a maximum achievable control technology (MACT) standard for mercury and other hazardous air pollutant emissions under the CAA. Under the terms of a consent decree, the Federal EPA is required to issue final MACT standards for coal and oil-fired power plants by November 2011. The Federal EPA has substantial discretion in determining how to structure the MACT standards. Management will urge the Federal EPA to carefully consider all of the options available so that costly and inefficient control requirements are not imposed regardless of unit size, age or other operating characteristics. However, the AEP System has approximately 5,000 MW of older coal units, including 2,000 MW of older coal-fired capacity already subject to control requirements under the NSR consent decree, for which it may be economically inefficient to install scrubbers or other environmental controls. The timing and ultimate disposition of those units will be affected by: a) the MACT standards and other environmental regulations, b) the economics of maintaining the units, c) demand for electricity, d) availability and cost of replacement power and e) regulatory decisions about cost recovery of the remaining investment in those units.

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.

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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 estimates that the potential compliance costs associated with the proposed solid waste management alternative could be as high as a total of $3.9 billion for units across the AEP System. Regulation of these materials as hazardous wastes would significantly increase these costs. The Registrant Subsidiaries will seek recovery of expenditures for pollution control technologies and associated costs from customers through regulated rates or market prices for electricity. If these costs are not recovered, it 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. These rules have been challenged in the courts. 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.

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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."

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 September 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 September 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.

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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.

MINE SAFETY INFORMATION

The Federal Mine Safety and Health Act of 1977 (Mine Act) imposes stringent health and safety standards on various mining operations. The Mine Act and its related regulations affect numerous aspects of mining operations, including training of mine personnel, mining procedures, equipment used in mine emergency procedures, mine plans and other matters. SWEPCo, through its ownership of DHLC, CSPCo, through its ownership of Conesville Coal Preparation Company (CCPC), and OPCo, through its use of the Connor Run fly ash impoundment, are subject to the provisions of the Mine Act.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires companies that operate mines to include in their periodic reports filed with the SEC, certain mine safety information covered by the Mine Act. DHLC, CCPC and Connor Run received the following notices of violation and proposed assessments under the Mine Act for the quarter ended September 30, 2010:

	DHLC	CCPC	Conner Run
Number of Citations for Violations of Mandatory Health or Safety Standards under 104 *	7	-	-
Number of Orders Issued under 104(b) *	-	-	-
Number of Citations and Orders for Unwarrantable Failure to Comply with Mandatory Health or Safety Standards under 104(d) *	1	-	-
Number of Flagrant Violations under 110(b)(2) *	-	-	-
Number of Imminent Danger Orders Issued under 107(a) *	-	-	-
Total Dollar Value of Proposed Assessments	$ 11,472	$ -	$ -
Number of Mining-related Fatalities	-	-	-

* References to sections under the Mine Act

DHLC currently has two legal actions pending before the Mine Safety and Health Administration (MSHA) challenging four violations issued by MSHA following an employee fatality in March 2009.

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, financial statements, 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.

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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)
Nine Months Ended September 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		(21,694)
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		(245)
Changes in Fair Value Due to Market Fluctuations During the Period (c)		61
Changes in Fair Value Allocated to Regulated Jurisdictions (d)		9,815
Total MTM Risk Management Contract Net Assets		33,134
Cash Flow Hedge Contracts		(4,513)
DETM Assignment (e)		(632)
Collateral Deposits		40,554
Total MTM Derivative Contract Net Assets at September 30, 2010	$	68,543

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		(12,940)
Fair Value of New Contracts at Inception When Entered During the Period (a)		7,641
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		(363)
Changes in Fair Value Due to Market Fluctuations During the Period (c)		6,615
Changes in Fair Value Allocated to Regulated Jurisdictions (d)		(5,062)
Total MTM Risk Management Contract Net Assets		21,506
Cash Flow Hedge Contracts		(2,320)

DETM Assignment (e)		(445)
Collateral Deposits		28,660
Total MTM Derivative Contract Net Assets at September 30, 2010	$	47,401

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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		263
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		(42)
Changes in Fair Value Due to Market Fluctuations During the Period (c)		(7)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)		3,190
Total MTM Risk Management Contract Net Assets		3,035
Cash Flow Hedge Contracts		-
DETM Assignment (e)		(16)
Collateral Deposits		55
Total MTM Derivative Contract Net Assets at September 30, 2010	$	3,074

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		(1,422)
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		(101)
Changes in Fair Value Due to Market Fluctuations During the Period (c)		-
Changes in Fair Value Allocated to Regulated Jurisdictions (d)		1,530
Total MTM Risk Management Contract Net Assets		1,643
Cash Flow Hedge Contracts		(71)
DETM Assignment (e)		(19)
Collateral Deposits		88
Total MTM Derivative Contract Net Assets at September 30, 2010	$	1,641

(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)
September 30, 2010
(in thousands)

APCo	Remainder 2010	2011-2013	2014+	Total
Level 1 (a)	$ 25	$ 36	$ -	$ 61
Level 2 (b)	3,183	7,092	1,411	11,686
Level 3 (c)	1,497	11,391	3,677	16,565
Total	4,705	18,519	5,088	28,312
Dedesignated Risk Management Contracts (d)	1,451	3,371	-	4,822
Total MTM Risk Management Contract Net Assets	$ 6,156	$ 21,890	$ 5,088	$ 33,134

OPCo	Remainder 2010	2011-2013	2014+	Total
Level 1 (a)	$ 18	$ 26	$ -	$ 44
Level 2 (b)	1,017	4,402	993	6,412
Level 3 (c)	1,054	8,016	2,587	11,657
Total	2,089	12,444	3,580	18,113
Dedesignated Risk Management Contracts (d)	1,021	2,372	-	3,393
Total MTM Risk Management Contract Net Assets	$ 3,110	$ 14,816	$ 3,580	$ 21,506

PSO	Remainder 2010	2011-2013	Total
Level 1 (a)	$ 1	$ -	$ 1
Level 2 (b)	1,731	1,301	3,032
Level 3 (c)	2	-	2
Total MTM Risk Management Contract Net Assets	$ 1,734	$ 1,301	$ 3,035

SWEPCo	Remainder 2010	2011-2013	Total
Level 1 (a)	$ 1	$ -	$ 1
Level 2 (b)	992	648	1,640
Level 3 (c)	2	-	2
Total MTM Risk Management Contract Net Assets	$ 995	$ 648	$ 1,643

(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 September 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 trading portfolio for the periods indicated:

	Nine Months Ended September 30, 2010				Twelve Months Ended December 31, 2009			
Company	End	High	Average	Low	End	High	Average	Low
	(in thousands)				(in thousands)			
APCo	$ 96	$ 659	$ 216	$ 71	$ 275	$ 699	$ 333	$ 151
OPCo	82	545	180	54	201	530	244	113
PSO	14	70	17	1	10	34	12	4
SWEPCo	20	93	24	2	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 September 30, 2010 and December 31, 2009, the estimated EaR on the Registrant Subsidiaries' debt portfolio was as follows:

Company	September 30, 2010	December 31, 2009

	(in thousands)	
APCo	$ 1,301	$ 1,837
CSPCo	202	216
I&M	337	227
OPCo	1,058	1,373
PSO	43	119
SWEPCo	666	305

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CONTROLS AND PROCEDURES

During the third 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 September 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 third 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.

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, plaintiffs filed with the Federal District Court for the Western District of Arkansas seeking a preliminary injunction to halt construction and for a temporary restraining order.

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 a temporary restraining order and preliminary injunction to stop construction of the Turk Plant asserting claims of violations of federal and state laws. This motion for preliminary injunction was heard simultaneously with the motion filed by the Sierra Club. In October 2010, the motions for preliminary injunction were partially granted. According to the preliminary injunction, all uncompleted construction work associated with wetlands, streams or rivers at the Turk Plant must immediately stop. Mitigation measures required by the permit are authorized and may be completed. The preliminary injunction affects portions of the water intake and associated piping and portions of the transmission lines. In October 2010, the Federal District Court certified issues relating to the state law claims to the Arkansas Supreme Court, including whether those claims are within the primary jurisdiction of the APSC. The Arkansas Supreme Court has yet to consider the request. SWEPCo filed a notice of appeal with the Federal Court of Appeals for the Eighth Circuit and is seeking a stay of the preliminary injunction pending appeal.

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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. 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.

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 impact financial condition.

Ohio may require us to refund revenue that we have collected. (Applies to AEP and CSPCo)

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. In September 2010, CSPCo and OPCo filed their 2009 SEET filings with the PUCO. CSPCo’s and OPCo’s returns on common equity were 20.84% and 10.81%, respectively, including off-system sales margins and 18.31% and 9.42%, respectively, excluding off-system sales margins. Included in the filings was CSPCo’s and OPCo’s determination that the level at which their earned return on common equity may become significantly in excess of the average earned return on common equity of the comparable risk group of publicly traded firms was 22.51%. Based upon the methodology proposed by CSPCo and OPCo in the SEET filings, neither CSPCo’s nor OPCo’s 2009 return on common equity was significantly excessive. In October 2010, intervenors filed testimony with the PUCO recommending CSPCo return up to $156 million of its ESP revenues to customers. If the PUCO determines that CSPCo’s and/or OPCo’s 2009 return on common equity was significantly excessive, CSPCo and/or OPCo may be required to return a portion of their ESP revenues to customers.

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 or potential other future adjustments 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 September 30, 2010, CSPCo and OPCo have incurred $39 million and $30 million, respectively, in EDR costs including carrying costs. Of these costs, CSPCo and OPCo have collected $27 million and $20 million, respectively, through the EDR, which CSPCo and OPCo began collecting in January 2010. The remaining $12 million and $10 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. In July 2010, Cities Advocating Reasonable Deregulation filed testimony regarding the 2007 transfer of ERCOT trading contracts to AEPEP. Included in this testimony were unquantified refund recommendations relating to re-pricing of contract transactions.

In September 2010, the Administrative Law Judges issued a Proposal for Decision (PFD) that recommended a disallowance of a significant portion of the charges to a ten-year gas transportation agreement that began in 2009 for the Mattison Plant located in Northwest Arkansas. The PFD stated that SWEPCo should have pursued other transportation options or sought the supplier's recourse rate from the FERC. The estimated recommended disallowance over the ten-year period through December 2018 is $107 million for which the estimated Texas jurisdictional portion is $37 million. In addition, the PFD also contained recommendations to disallow risk premiums related to the ERCOT trading contracts transferred to AEPEP which are estimated to be $1.5 million on a Texas retail jurisdictional basis. Through September 30, 2010, SWEPCo's management estimated the impact of this PFD, if adopted by the PUCT, to be $7 million. In October 2010, SWEPCo filed exceptions on these issues with the PUCT. An order may be issued in the fourth quarter of 2010. 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.

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 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. In October 2010, various parties filed testimony. The parties' net annual rate recommendations ranged from a rate reduction of $18 million to an increase of less than $1 million. If the OCC denies all or part of the requested rate recovery, it could reduce future net income and cash flows.

Risks Related to State Restructuring

Our customers have recently begun to select alternative electric generation service providers, as allowed by Ohio legislation. (Applies to AEP and CSPCo)

Under current Ohio legislation, electric generation is sold in a competitive market in Ohio, and our native load customers in Ohio have the ability to switch to alternative suppliers for their electric generation service. Competitive power suppliers are targeting retail customers by offering alternative generation service. A growing number of CSPCo's commercial retail customers have switched to alternative generation providers while additional Ohio customers have provided notice of their intent to switch. These evolving market conditions may continue to impact CSPCo's results of operations and its ability to apply regulatory accounting treatment to certain portions of its operations.

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 September 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
07/01/10 – 07/31/10	-	$ -	-	$ -
08/01/10 – 08/31/10	6 (a)	71.50	-	-
09/01/10 – 09/30/10	-	-	-	-

(a) APCo purchased 3 shares of its 4.50% cumulative preferred stock and I&M purchased 3 shares of its 4.125% cumulative preferred stock in privately-negotiated transactions outside of an announced program.

Item 5. Other Information

NONE

Item 6. Exhibits

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: November 1, 2010

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