Kentucky Power Company

2009 Annual Report

Financial Statements

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GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEP West companies	PSO, SWEPCo, TCC and TNC.
ALJ	Administrative Law Judge.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
CO_2	Carbon Dioxide and other greenhouse gases.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation. AEPSC acts as the agent.
CWIP	Construction Work in Progress.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company.
ERCOT	Electric Reliability Council of Texas.
FAC	Fuel Adjustment Clause.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
KGPCo	Kingsport Power Company, an AEP electric distribution subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
MISO	Midwest Independent Transmission System Operator.
MMBtus	Million British Thermal Units.
MLR	Member load ratio, the method used to allocate AEP Power Pool transactions to its members.
MTM	Mark-to-Market.
MW	Megawatt.

Term	Meaning
NO_x	Nitrogen oxide.
OCC	Corporation Commission of the State of Oklahoma.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana.
RTO	Regional Transmission Organization.
S&P	Standard and Poor's.
SIA	System Integration Agreement.
SO_2	Sulfur Dioxide.
SPP	Southwest Power Pool.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Utility Money Pool	AEP System's Utility Money Pool.
WPCo	Wheeling Power Company, an AEP electric distribution subsidiary.

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Shareholder of
Kentucky Power Company:

We have audited the accompanying balance sheets of Kentucky Power Company (the "Company") as of December 31, 2009 and 2008, and the related statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards as established by the Auditing Standards Board (United States) and in accordance with the auditing standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Kentucky Power Company as of December 31, 2009 and 2008, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 26, 2010

KENTUCKY POWER COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2009, 2008 and 2007
(in thousands)

	2009	2008	2007
REVENUES			
Electric Generation, Transmission and Distribution	$ 567,564	$ 597,699	$ 526,754
Sales to AEP Affiliates	62,613	66,249	60,551
Other Revenues	2,349	1,612	695
TOTAL REVENUES	632,526	665,560	588,000
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	188,525	171,215	147,912
Purchased Electricity for Resale	24,839	26,157	17,786
Purchased Electricity from AEP Affiliates	198,320	234,379	185,399
Other Operation	51,417	64,330	66,118
Maintenance	38,888	47,921	36,880
Depreciation and Amortization	52,010	48,067	47,193
Taxes Other Than Income Taxes	11,738	9,644	11,872
TOTAL EXPENSES	565,737	601,713	513,160
OPERATING INCOME	66,789	63,847	74,840
Other Income (Expense):			
Interest Income	218	2,103	1,992
Allowance for Equity Funds Used During Construction	391	1,012	260
Interest Expense	(33,812)	(34,535)	(28,635)
INCOME BEFORE INCOME TAX EXPENSE	33,586	32,427	48,457
Income Tax Expense	9,650	7,896	15,987
NET INCOME	$ 23,936	$ 24,531	$ 32,470

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

See Notes to Financial Statements.

KENTUCKY POWER COMPANY
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2009, 2008 and 2007
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2006	$ 50,450	$ 208,750	$ 108,899	$ 1,552	$ 369,651
Adoption of Guidance for Uncertainty in Income Taxes, Net of Tax			(786)		(786)
Common Stock Dividends			(12,000)		(12,000)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					356,865
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,274				(2,366)	(2,366)
NET INCOME			32,470		32,470
TOTAL COMPREHENSIVE INCOME					30,104
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2007	50,450	208,750	128,583	(814)	386,969
Adoption of Guidance for Split-Dollar Life Insurance Accounting, Net of Tax of $197			(365)		(365)
Common Stock Dividends			(14,000)		(14,000)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					372,604
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $470				873	873
NET INCOME			24,531		24,531
TOTAL COMPREHENSIVE INCOME					25,404
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2008	50,450	208,750	138,749	59	398,008
Capital Contribution from Parent		30,000			30,000
Common Stock Dividends			(19,500)		(19,500)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					408,508
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $355				(660)	(660)
NET INCOME			23,936		23,936
TOTAL COMPREHENSIVE INCOME					23,276
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2009	$ 50,450	$ 238,750	$ 143,185	$ (601)	$ 431,784

See Notes to Financial Statements.

KENTUCKY POWER COMPANY
BALANCE SHEETS
ASSETS
December 31, 2009 and 2008
(in thousands)

	2009	2008
CURRENT ASSETS		
Cash and Cash Equivalents	$ 494	$ 646
Accounts Receivable:		
Customers	17,593	21,681
Affiliated Companies	8,692	6,721
Accrued Unbilled Revenues	4,806	2,533
Miscellaneous	1,304	83
Allowance for Uncollectible Accounts	(851)	(1,144)
Total Accounts Receivable	31,544	29,874
Fuel	36,168	29,440
Materials and Supplies	18,248	10,630
Risk Management Assets	13,687	13,760
Accrued Tax Benefits	29,540	41
Regulatory Asset for Under-Recovered Fuel Costs	-	9,953
Margin Deposits	5,925	5,207
Prepayments and Other Current Assets	2,416	5,710
TOTAL CURRENT ASSETS	138,022	105,261
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	547,378	533,998
Transmission	438,775	431,835
Distribution	569,389	528,711
Other Property, Plant and Equipment	59,002	65,485
Construction Work in Progress	28,409	46,650
Total Property, Plant and Equipment	1,642,953	1,606,679
Accumulated Depreciation and Amortization	508,806	476,568
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,134,147	1,130,111
OTHER NONCURRENT ASSETS		
Regulatory Assets	206,074	179,845
Long-term Risk Management Assets	9,498	10,860
Deferred Charges and Other Noncurrent Assets	40,178	41,884
TOTAL OTHER NONCURRENT ASSETS	255,750	232,589
TOTAL ASSETS	$ 1,527,919	$ 1,467,961

See Notes to Financial Statements.

KENTUCKY POWER COMPANY
BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
December 31, 2009 and 2008

	2009	2008
CURRENT LIABILITIES	(in thousands)	
Advances from Affiliates	$ 485	$ 131,399
Accounts Payable:		
General	42,595	35,584
Affiliated Companies	27,341	45,245
Risk Management Liabilities	5,190	6,316
Customer Deposits	18,258	15,985
Accrued Taxes	12,625	11,903
Accrued Interest	7,466	7,009
Other Current Liabilities	26,996	22,517
TOTAL CURRENT LIABILITIES	140,956	275,958
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	528,722	398,555
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	4,101	5,630
Deferred Income Taxes	304,549	259,666
Regulatory Liabilities and Deferred Investment Tax Credits	35,678	46,135
Employee Benefits and Pension Obligations	49,843	51,819
Deferred Credits and Other Noncurrent Liabilities	12,286	12,190
TOTAL NONCURRENT LIABILITIES	955,179	793,995
TOTAL LIABILITIES	1,096,135	1,069,953
Rate Matters (Note 2)		
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	238,750	208,750
Retained Earnings	143,185	138,749
Accumulated Other Comprehensive Income (Loss)	(601)	59
TOTAL COMMON SHAREHOLDER'S EQUITY	431,784	398,008
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 1,527,919	$ 1,467,961

See Notes to Financial Statements.

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2009, 2008 and 2007
(in thousands)

	2009	2008	2007
OPERATING ACTIVITIES			
Net Income	$ 23,936	$ 24,531	$ 32,470
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	52,010	48,067	47,193
Deferred Income Taxes	50,612	4,097	5,691
Allowance for Equity Funds Used During Construction	(391)	(1,012)	(260)
Mark-to-Market of Risk Management Contracts	(2,386)	(4,650)	89
Fuel Over/Under-Recovery, Net	11,740	(5,528)	(3,383)
Deferral of Storm Costs	(24,355)	-	-
Change in Other Noncurrent Assets	1,452	(11,298)	(4,122)
Change in Other Noncurrent Liabilities	(2,943)	2,055	1,001
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(444)	8,317	2,445
Fuel, Materials and Supplies	(13,643)	(18,866)	9,015
Accounts Payable	(7,149)	21,288	1,806
Accrued Taxes, Net	(29,470)	(4,199)	(1,410)
Other Current Assets	(1,177)	(3,953)	415
Other Current Liabilities	(2,997)	2,473	2,744
Net Cash Flows from Operating Activities	54,795	61,322	93,694
INVESTING ACTIVITIES			
Construction Expenditures	(63,963)	(129,619)	(68,134)
Acquisitions of Assets	(316)	(314)	-
Proceeds from Sales of Assets	927	947	695
Net Cash Flows Used for Investing Activities	(63,352)	(128,986)	(67,439)
FINANCING ACTIVITIES			
Capital Contribution from Parent	30,000	-	-
Issuance of Long-term Debt – Nonaffiliated	129,292	-	321,100
Change in Advances from Affiliates, Net	(130,914)	112,246	(11,483)
Retirement of Long-term Debt – Nonaffiliated	-	(30,000)	(322,964)
Principal Payments for Capital Lease Obligations	(749)	(806)	(883)
Dividends Paid on Common Stock	(19,500)	(14,000)	(12,000)
Other Financing Activities	276	143	-
Net Cash Flows from (Used for) Financing Activities	8,405	67,583	(26,230)
Net Increase (Decrease) in Cash and Cash Equivalents	(152)	(81)	25
Cash and Cash Equivalents at Beginning of Period	646	727	702
Cash and Cash Equivalents at End of Period	$ 494	$ 646	$ 727
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 37,402	$ 28,602	$ 28,864
Net Cash Paid (Received) for Income Taxes	(8,713)	3,554	10,477
Noncash Acquisitions Under Capital Leases	829	544	826
Construction Expenditures Included in Accounts Payable at December 31,	5,451	9,662	12,161
SIA Refund Included in Accounts Payable at December 31,	-	18,526	-

See Notes to Financial Statements.

INDEX TO NOTES TO FINANCIAL STATEMENTS

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

As a public utility, KPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 175,000 retail customers in its service territory in eastern Kentucky. As a member of the AEP Power Pool, KPCo shares the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers. KPCo also sells power at wholesale to municipalities.

The cost of the AEP Power Pool's generating capacity is allocated among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold and relative peak demand changes. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each member's percentage share of revenues and costs.

Under a unit power agreement with AEGCo, an affiliated company that is not a member of the AEP Power Pool, KPCo purchases 15% of the total output of the 2,600 MW Rockport Plant capacity. Therefore, KPCo purchases 390 MW of Rockport Plant capacity. The unit power agreement expires in December 2022. KPCo pays a demand charge for the right to receive the power, which is payable even if the power is not taken.

Under the SIA, AEPSC allocates physical and financial revenues and expenses from neighboring utilities, power marketers and other power and gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among the AEP East companies, PSO and SWEPCo in proportion to the marketing realization directly assigned to each zone for the current month plus the preceding eleven months.

AEPSC conducts power, gas, coal and emission allowance risk management activities on KPCo's behalf. KPCo shares in the revenues and expenses associated with these risk management activities, as described in the preceding paragraph, with the other AEP East companies, PSO and SWEPCo. Power and gas risk management activities are allocated based on the existing power pool agreement and the SIA. KPCo shares in coal and emission allowance risk management activities based on its proportion of fossil fuels burned by the AEP System. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas, coal and emission allowances. The electricity, gas, coal and emission allowance contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. KPCo settles the majority of the physical forward contracts by entering into offsetting contracts.

To minimize the credit requirements and operating constraints when operating within PJM, the AEP East companies as well as KGPCo and WPCo, agreed to a netting of all payment obligations incurred by any of the AEP East companies against all balances due to the AEP East companies, and to hold PJM harmless from actions that any one or more AEP East companies may take with respect to PJM.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

KPCo's rates are regulated by the FERC and the KPSC. The FERC also regulates KPCo's affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over the issuances and acquisitions of securities of the public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. For non-power goods and services, the FERC requires that a nonregulated affiliate can bill an affiliated public utility company no more than market while a public utility must bill the higher of cost or market to a nonregulated affiliate.

The FERC regulates wholesale power markets, wholesale power transactions and wholesale transmission operations and rates. KPCo's wholesale power transactions are generally market-based. They are cost-based regulated when KPCo negotiates and files a cost-based contract with the FERC or the FERC determines that KPCo has "market power" in the region where the transaction occurs. KPCo has entered into wholesale power supply contracts with various municipalities and cooperatives that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are trued up to actual costs annually.

The KPSC regulates all of the distribution operations and rates and retail transmission rates on a cost basis. They also regulate the retail generation/power supply operations and rates.

In addition, the FERC regulates the SIA, the Interconnection Agreement, the System Transmission Integration Agreement, the Transmission Agreement and the AEP System Interim Allowance Agreement, all of which allocate shared system costs and revenues to the utility subsidiaries that are parties to each agreement.

Both the FERC and state regulatory commissions are permitted to review and audit the books and records of any company within a public utility holding company system.

Accounting for the Effects of Cost-Based Regulation

As a rate-regulated electric public utility company, KPCo's financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with accounting guidance for "Regulated Operations," KPCo records regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues and income with its passage to customers through the reduction of regulated revenues.

Use of Estimates

The preparation of these financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include but are not limited to inventory valuation, allowance for doubtful accounts, long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Cash and Cash Equivalents

Cash and Cash Equivalents include temporary cash investments with original maturities of three months or less.

Inventory

Fossil fuel inventories and materials and supplies inventories are carried at average cost.

Accounts Receivable

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to risk management activities and customer receivables primarily related to other revenue-generating activities.

Revenue is recognized from electric power sales when power is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, KPCo accrues and recognizes, as Accrued Unbilled Revenues, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable, excluding receivables from risk management activities, for KPCo. AEP Credit has a sale of receivables agreement with bank conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the bank conduits and receives cash. This transaction constitutes a sale of receivables in accordance with the accounting guidance for "Transfers and Servicing," allowing the receivables to be removed from KPCo's balance sheet (see "Sale of Receivables - AEP Credit" section of Note 11). The new accounting guidance for "Transfers and Servicing," effective January 1, 2010, has no impact on KPCo.

Concentrations of Credit Risk and Significant Customers

KPCo does not have any significant customers that comprise 10% or more of its Operating Revenues as of December 31, 2009.

KPCo monitors credit levels and the financial condition of its customers on a continuing basis to minimize credit risk. The KPSC allows recovery in rates for a reasonable level of bad debt costs. Management believes adequate provision for credit loss has been made in the accompanying financial statements.

Emission Allowances

KPCo records emission allowances at cost, including the annual SO_2 and NO_x emission allowance entitlements received at no cost from the Federal EPA. KPCo follows the inventory model for these allowances. Allowances expected to be consumed within one year are reported in Materials and Supplies. Allowances with expected consumption beyond one year are included in Other Noncurrent Assets-Deferred Charges and Other. These allowances are consumed in the production of energy and are recorded in Fuel and Other Consumables Used for Electric Generation at an average cost. Allowances held for speculation are included in Current Assets-Prepayments and Other. The purchases and sales of allowances are reported in the Operating Activities section of the Statements of Cash Flows. The net margin on sales of emission allowances is included in Electric Generation, Transmission and Distribution Revenues for nonaffiliated transactions and in Sales to AEP Affiliates Revenues for affiliated transactions because of its integral nature to the production process of energy and KPCo's revenue optimization strategy for operations. The net margin on sales of emission allowances affects the determination of deferred fuel or deferred emission allowance costs and the amortization of regulatory assets.

Property, Plant and Equipment

Electric utility property, plant and equipment are stated at original purchase cost. Additions, major replacements and betterments are added to the plant accounts. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation under the group composite method of depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in the original cost, less salvage, being charged to accumulated depreciation. The depreciation rates that are established for the generating plants take into account the past history of interim capital replacements and the amount of salvage received. These rates and the related lives are subject to periodic review. Removal costs are charged to regulatory liabilities. The costs of labor, materials and overhead incurred to operate and maintain the plants are included in operating expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held for sale criteria under the accounting guidance for "Impairment or Disposal of Long-lived Assets."

The fair value of an asset and investment is the amount at which that asset and investment could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets or investments in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Allowance for Funds Used During Construction (AFUDC)

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant.

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Accounts Receivable and Accounts Payable approximate fair value because of the short-term maturity of these instruments.

Fair Value Measurements of Assets and Liabilities

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 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 to estimate the fair value of the underlying investments held in the benefit plan 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 plans. 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. Benefit plan assets included in Level 3 are real estate and private equity investments that are valued using methods requiring judgment including appraisals.

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. Fuel cost over-recoveries (the excess of fuel revenues billed to customers over applicable fuel costs incurred) are deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel revenues billed to customers) are deferred as current regulatory assets. These deferrals are amortized when refunded or when billed to customers in later months with the KPSC's review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the KPSC. On a routine basis, the KPSC reviews and/or audits KPCo's fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. When a fuel cost disallowance becomes probable, KPCo adjusts its FAC deferrals and records a provision for estimated refunds to recognize these probable outcomes. Changes in fuel costs, including purchased power are reflected in rates in a timely manner through the FAC. A portion of profits from off-system sales are shared with customers through the FAC.

Revenue Recognition

Regulatory Accounting

KPCo's financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

When regulatory assets are probable of recovery through regulated rates, KPCo records them as assets on its balance sheet. KPCo tests for probability of recovery at each balance sheet date or whenever new events occur. Examples of new events include the issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, KPCo writes off that regulatory asset as a charge against income.

Traditional Electricity Supply and Delivery Activities

KPCo recognizes revenues from retail and wholesale electricity sales and electricity transmission and distribution delivery services. KPCo recognizes the revenues in the financial statements upon delivery of the energy to the customer and includes unbilled as well as billed amounts.

Most of the power produced at the generation plants of the AEP East companies is sold to PJM, the RTO operating in the east service territory. The AEP East companies purchase power from PJM to supply power to their customers. Generally, these power sales and purchases are reported on a net basis in Revenues in the Statements of Income. However, in 2009, there were times when the AEP East companies were a purchaser of power from PJM to serve retail load. These purchases were recorded gross as Purchased Electricity for Resale on the Statements of Income. Other RTOs do not function in the same manner as PJM. They function as balancing organizations and not as exchanges.

Physical energy purchases, including those from all RTOs, that are identified as non-trading, but excluding PJM purchases described in the preceding paragraph, are accounted for on a gross basis in Purchased Electricity for Resale in the Statements of Income.

KPCo records expenses upon receipt of purchased electricity and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting. KPCo, which operates solely in a jurisdiction where the generation /supply business is subject to cost-based regulation, defers the unrealized MTM amounts as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

AEPSC, on behalf of the AEP East companies, engages in wholesale electricity, natural gas, coal and emission allowances marketing and risk management activities focused on wholesale markets where the AEP System owns assets and adjacent markets. These activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts which include exchange traded futures and options, and over-the-counter options and swaps. Certain energy marketing and risk management transactions are with RTOs.

KPCo recognizes revenues and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. KPCo uses MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or a normal purchase or sale. The realized gains and losses on wholesale marketing and risk management transactions are included in Revenues in the Statements of Income on a net basis. The unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains). Unrealized MTM gains and losses are included on the balance sheets as Risk Management Assets or Liabilities as appropriate.

Certain qualifying wholesale marketing and risk management derivative transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). KPCo initially records the effective portion of the cash flow hedge's gain or loss as a component of AOCI. When the forecasted transaction is realized and affects net income, KPCo subsequently reclassifies the gain or loss on the hedge from Accumulated Other Comprehensive Income into revenues or expenses within the same financial statement line item as the forecasted transaction on its Statements of Income. KPCo defers the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains). See "Accounting for Cash Flow Hedging Strategies" section of Note 7.

Maintenance

Maintenance costs are expensed as incurred. If it becomes probable that KPCo will recover specifically-incurred costs through future rates, a regulatory asset is established to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues.

Income Taxes and Investment Tax Credits

KPCo uses the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence.

When the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

Investment tax credits are accounted for under the flow-through method except where regulatory commissions have reflected investment tax credits in the rate-making process on a deferral basis. Investment tax credits that have been deferred are amortized over the life of the plant investment.

KPCo accounts for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." KPCo classifies interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classifies penalties as Other Operation.

Excise Taxes

As an agent for some state and local governments, KPCo collects from customers certain excise taxes levied by those state or local governments on customers. KPCo does not record these taxes as revenue or expense.

Debt

Gains and losses from the reacquisition of debt used to finance regulated electric utility plants are deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt is refinanced, the reacquisition costs are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates.

Debt discount or premium and debt issuance expenses are deferred and amortized generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. The net amortization expense is included in Interest Expense.

Investments Held in Trust for Future Liabilities

AEP has several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits. All of the trust funds' investments are diversified and managed in compliance with all laws and regulations. The investment strategy for trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the interest rate sensitivity of the assets relative to the associated liabilities. To minimize investment risk, the trust funds are broadly diversified among classes of assets, investment strategies and investment managers. Management regularly reviews the actual asset allocation and periodically rebalance the investments to targeted allocation when appropriate. Investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. The investments are reported at fair value under the "Fair Value Measurements and Disclosures" accounting guidance.

Benefit Plans

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies and target asset allocations by plan.

The investment philosophies for AEP's benefit plans support the allocation of assets to minimize risks and optimizing net returns. Strategies used include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable level.
- Managing fees, transaction costs and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style-neutral to limit volatility compared to applicable benchmarks.
- Using alternative asset classes such as real estate and private equity to maximize return and provide additional portfolio diversification.

The target asset allocation and allocation ranges are as follows:

Pension Plan Assets	Minimum	Target	Maximum
Domestic Equity	30.0%	35.0%	40.0%
International and Global Equity	10.0%	15.0%	20.0%
Fixed Income	35.0%	39.0%	45.0%
Real Estate	4.0%	5.0%	6.0%
Other Investments	1.0%	5.0%	7.0%
Cash	0.5%	1.0%	3.0%

OPEB Plans Assets	Minimum	Target	Maximum
Equity	61.0%	66.0%	71.0%
Fixed Income	29.0%	33.0%	37.0%
Cash	1.0%	1.0%	4.0%

The investment policy for each benefit plan contains various investment limitations. The investment policies establish concentration limits for securities. Investment policies prohibit the benefit trust funds from purchasing securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, the investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law. Each investment manager's portfolio is compared to a diversified benchmark index.

For equity investments, the limits are as follows:

- No security in excess of 5% of all equities.
- Cash equivalents must be less than 10% of an investment manager's equity portfolio.
- Individual stock must be less than 10% of each manager's equity portfolio.
- No investment in excess of 5% of an outstanding class of any company.
- No securities may be bought or sold on margin or other use of leverage.

For fixed income investments, the concentration limits must not exceed:

- 3% in one issuer
- 20% in non-US dollar denominated
- 5% private placements
- 5% convertible securities
- 60% for bonds rated AA+ or lower
- 50% for bonds rated A+ or lower
- 10% for bonds rated BBB- or lower

For obligations of non-government issuers the following limitations apply:

- AAA rated debt: a single issuer should account for no more than 5% of the portfolio.
- AA+, AA, AA- rated debt: a single issuer should account for no more than 3% of the portfolio.
- Debt rated A+ or lower: a single issuer should account for no more than 2% of the portfolio.
- No more than 10% of the portfolio may be invested in high yield and emerging market debt combined at any time.

A portion of the pension assets is invested in real estate funds to provide diversification, add return, and hedge against inflation. Real estate properties are illiquid, difficult to value, and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type, and risk classification. Real estate holdings include core, value-added, and development risk classifications and some investments in Real Estate Investment Trusts (REITs), which are publicly traded real estate securities classified as Level 1.

A portion of the pension assets is invested in private equity. Private equity investments add return and provide diversification and typically require a long-term time horizon to evaluate investment performance. Private equity is classified as an alternative investment because it is illiquid, difficult to value, and not actively traded. The pension plan uses limited partnerships and commingled funds to invest across the private equity investment spectrum. The private equity holdings are with six general partners who help monitor the investments and provide investment selection expertise. The holdings are currently comprised of venture capital, buyout, and hybrid debt and equity investment instruments. Commingled private equity funds are used to enhance the holdings' diversity.

AEP participates in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. AEP lends securities to borrowers approved by BNY Mellon in exchange for cash collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the cash collateral is invested. The difference between the rebate owed to the borrower and the cash collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is providing modest incremental income with a limited increase in risk.

Trust owned life insurance (TOLI) underwritten by The Prudential Insurance Company is held in the OPEB plan trusts. The strategy for holding life insurance contracts in the taxable VEBA trust is to minimize taxes paid on the asset growth in the trust. Earnings on plan assets are tax-deferred within the TOLI contract and can be tax-free if held until claims are paid. Life insurance proceeds remain in the trust and are used to fund future retiree medical benefit liabilities. With consideration to other investments held in the trust, the cash value of the TOLI contracts is invested in two diversified funds. A portion is invested in a commingled fund with underlying investments in stocks that are actively traded on major international equity exchanges. The other portion of the TOLI cash value is invested in a diversified, commingled fixed income fund with underlying investments in government bonds, corporate bonds and asset-backed securities.

Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments including commercial paper, certificates of deposit, treasury bills and other types of investment grade short-term debt securities. The cash funds are valued each business day and provide daily liquidity.

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from nonowner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

Components of Accumulated Other Comprehensive Income (Loss) (AOCI)

AOCI is included on the balance sheets in the common shareholder's equity section. AOCI for KPCo as of December 31, 2009 and 2008 is shown in the following table:

	December 31,	
Components	**2009**	**2008**
	(in thousands)	
Cash Flow Hedges, Net of Tax	$ (601)	$ 59

Earnings Per Share (EPS)

KPCo is a wholly-owned subsidiary of AEP. Therefore, KPCo is not required to report EPS.

Subsequent Events

Management reviewed subsequent events through February 26, 2010, the date that KPCo's 2009 annual report was issued.

2. RATE MATTERS

KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. Rate matters can have a material effect on financial condition, net income and cash flows. KPCo's recent significant rate orders and pending rate filings are addressed in this note.

KENTUCKY RATE MATTERS

Validity of Nonstatutory Surcharges

The Franklin County Circuit Court concluded the KPSC did not have the authority to order a surcharge for a gas company subsidiary of Duke Energy absent a full cost of service rate proceeding due to the lack of statutory authority. Both the KPSC and Duke Energy appealed the Franklin County Circuit Court decision. Although this order is not directly applicable, KPCo has existing surcharges which are not specifically authorized by statute. These include KPCo's fuel clause surcharge, the annual Rockport Plant capacity surcharge, the merger surcredit and the off-system sales credit rider. On an annual basis, these surcharges ranged from revenues of approximately $11 million to a reduction of revenues of $5 million due to the volatility of these surcharges. The KPSC asked interested parties to brief the issue in KPCo's fuel cost proceeding. The Kentucky Attorney General responded that the KPCo fuel clause should be invalidated because the KPSC lacked the authority to implement a fuel clause for KPCo without a full rate case review.

The Kentucky Court of Appeals concluded that Duke Energy's surcharge was illegal. However, the order stated that the "decision was premised on the nature of the long-term capital improvements proposed by Duke Energy as distinguished from the fuel and other surcharges that are fluctuating and unanticipated. The latter have been approved by the Kentucky Supreme Court and remain the law." The KPSC filed for a discretionary review of the related Duke Energy case with the Kentucky Supreme Court. Management believes that all of KPCo's variable rate mechanisms are valid and would be upheld if challenged. If KPCo's variable rate mechanisms are found to be invalid, it could have an adverse impact on net income, cash flows and financial condition.

Kentucky Base Rate Filing

In December 2009, KPCo filed a base rate case with the KPSC to increase base revenues by $124 million annually based on an 11.75% return on common equity. New rates are scheduled to become effective in July 2010.

FERC RATE MATTERS

Regional Transmission Rate Proceedings at the FERC

Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund

In 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected, at the FERC's direction, load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 2006. Intervenors objected to the temporary SECA rates. The FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies recognized gross SECA revenues of $220 million from 2004 through 2006 when the SECA rates terminated leaving the AEP East companies and ultimately their internal load retail customers to make up the shortfall in revenues. KPCo's portion of recognized gross SECA revenues was $17 million.

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. Management believes that the FERC should reject the ALJ's initial decision because it contradicts prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ's findings on key issues are largely without merit. AEP and SECA ratepayers have been engaged in settlement discussions in an effort to settle the SECA issue. However, if the ALJ's initial decision is upheld in its entirety, it could result in a refund of a portion or all of the unsettled SECA revenues. In December 2009, several parties filed a motion with the U.S. Court of Appeals to force the FERC to resolve the SECA issue.

The AEP East companies provided reserves for net refunds for SECA settlements totaling $44 million applicable to the $220 million of SECA revenues collected. KPCo provided reserves of $3.3 million.

Through 2009, 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 December 31, 2009 was $34 million. KPCo's portion of the reserve balance at December 31, 2009 was $2.6 million. As of December 31, 2009, there were no in-process settlements.

Based on settlement experience and the expectation that most of the unsettled SECA revenues will be settled, management believes that the available reserve of $34 million is adequate to settle the remaining $108 million of contested SECA revenues. Management cannot predict the ultimate outcome of future settlement discussions or future FERC proceedings or court appeals. However, if the FERC adopts the ALJ's decision and/or AEP cannot settle all of the remaining unsettled claims within the remaining amount reserved for refund, it would reduce future net income and cash flows.

Allocation of Off-system Sales Margins

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 2008, the FERC issued a final order concluding that AEP inappropriately deviated from off-system sales margin allocation methods in the SIA and the CSW Operating Agreement for the period June 2000 through March 2006. The FERC ordered AEP to recalculate and reallocate the off-system sales margins in compliance with the SIA and to have the AEP East companies issue refunds to the AEP West companies. Although the FERC determined that AEP deviated from the CSW Operating Agreement, the FERC determined the allocation methodology was reasonable. The FERC ordered AEP to submit a revised CSW Operating Agreement for the period June 2000 to March 2006. AEP filed a motion for rehearing and a revised CSW Operating Agreement for the period June 2000 to March 2006. In February 2010, the FERC denied AEP's motion for rehearing. In 2009, AEP made a compliance filing with the FERC and the AEP East companies refunded approximately $250 million to the AEP West companies.

Modification of the Transmission Agreement (TA)

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

PJM/MISO Market Flow Calculation Errors

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 is disputing PJM's methodology. The FERC is scheduling settlement discussions to resolve the claims. If the FERC approves a settlement above the amount the AEP East companies have recognized related to their portions of PJM's additional costs, it could reduce net income and cash flows.

PJM Transmission Formula Rate Filing

AEP filed an application with the FERC to increase its open access transmission tariff (OATT) rates for wholesale transmission service within PJM. The filing seeks 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, subject to a compliance filing, established a settlement proceeding with an ALJ and delayed the requested October 2008 effective date for five months. AEP filed the required compliance filing and began settlement discussions with the intervenors and FERC staff. The settlement discussions are currently ongoing.

The requested $63 million increase began in March 2009. Approximately $8 million of the increase will be collected from nonaffiliated customers within PJM. The remaining $55 million requested would be billed to the AEP East companies but would be offset by compensation from PJM for use of the AEP East companies' transmission facilities so that retail rates for jurisdictions other than Ohio were not directly affected.

The first annual update of the formula rate was filed with the FERC which reflected transmission service revenue requirements of an additional $32 million on an annualized basis, effective for service as of July 2009. Approximately $4 million of the increase will be collected from nonaffiliated customers within PJM.

Under the formula, the second annual update will be filed 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. Management is unable to predict the outcome of the settlement discussions or any further proceedings that might be necessary if settlement discussions are not successful.

Transmission Agreement (TA)

Certain transmission facilities placed in service in 1998 in KPCo's service territory were inadvertently excluded from the AEP East companies' TA calculation. As a result, KPCo did not receive a TA credit for this equipment from the other TA member companies. The amount involved was $7 million annually. It was not discovered until February 2009. KPCo's base electric rates were adjusted only once, in April 2006, during the period in which the error was in effect. Effective January 2009, the allocation was revised to give KPCo its full TA credit prospectively and the KPSC staff and attending intervenor were informed about the revision at a meeting in April 2009. Management does not believe that it is probable that a material retroactive rate adjustment will result.

3. EFFECTS OF REGULATION

Regulatory assets and liabilities are comprised of the following items:

	December 31, 2009	December 31, 2008	Remaining Recovery Period
Regulatory Assets:	(in thousands)		
Current Regulatory Asset			
Under-recovered Fuel Costs – does not earn a return	$ -	$ 9,953	
Noncurrent Regulatory Assets			
Regulatory assets not yet being recovered. Recovery method and timing to be determined in future proceedings:			
Regulatory Assets Currently Not Earning a Return			
Storm Related Costs (a)	$ 24,355	$ -	
Total Regulatory Assets Not Yet Being Recovered	24,355	-	
Regulatory assets being recovered:			
Regulatory Assets Currently Not Earning a Return			
Income Taxes, Net	114,131	107,953	23 years
Pension and OPEB Funded Status	56,848	61,439	10 to 14 years
Postemployment Benefits	7,077	6,881	5 years
Total Regulatory Assets Being Recovered	178,056	176,273	
Other	3,663	3,572	various
Total Noncurrent Regulatory Assets	$ 206,074	$ 179,845	

(a) Authorization to establish a $10,306 thousand regulatory asset received from the KPSC.

	December 31, 2009	December 31, 2008	Remaining Refund Period
Regulatory Liabilities:	(in thousands)		
Current Regulatory Liability			
Over-recovered Fuel Costs – does not pay a return	$ 1,787	$ -	1 year
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	$ 24,979	$ 31,874	(a)
Regulatory Liabilities Currently Not Paying a Return			
Unrealized Gain on Forward Commitments	8,977	11,697	5 years
Deferred Investment Tax Credits	1,697	2,519	11 years
Regulatory Liabilities Being Paid	35,653	46,090	
Other	25	45	various
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 35,678	$ 46,135	

(a) Relieved as removal costs are incurred.

4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, KPCo's 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.

COMMITMENTS

KPCo has substantial construction commitments to support its operations and environmental investments. In managing the overall construction program and in the normal course of business, KPCo contractually commits to third-party construction vendors for certain material purchases and other construction services. KPCo also purchases fuel, materials, supplies, services and property, plant and equipment under contract as part of its normal course of business. Certain supply contracts contain penalty provisions for early termination.

The following table summarizes KPCo's actual contractual commitments at December 31, 2009:

Contractual Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 116.0	$ 143.4	$ 6.6	$ -	$ 266.0
Energy and Capacity Purchase Contracts (b)	1.4	1.3	-	-	2.7
Construction Contracts for Capital Assets (c)	0.1	0.5	1.4	-	2.0
Total	$ 117.5	$ 145.2	$ 8.0	$ -	$ 270.7

(a) Represents contractual commitments to purchase coal, natural gas and other consumables as fuel for electric generation along with related transportation of the fuel.
(b) Represents contractual commitments for energy and capacity purchase contracts.
(c) Represents only capital assets that are contractual commitments. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs.

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.

Indemnifications and Other Guarantees

Contracts

KPCo enters 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 December 31, 2009, KPCo entered into sale agreements including indemnifications with a maximum exposure that was not significant. There are no material liabilities recorded for any indemnifications.

KPCo, along with the other 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 purchase power and sale activity conducted pursuant to the SIA.

Lease Obligations

KPCo leases certain equipment under master lease agreements. See "Master Lease Agreements" section of Note 10 for disclosure of lease residual value guarantees.

CONTINGENCIES

Insurance and Potential Losses

KPCo maintains insurance coverage normal and customary for an electric utility, subject to various deductibles. The insurance includes coverage for all risks of physical loss or damage to assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. The insurance programs also generally provide coverage against loss arising from certain claims made by third parties and are in excess of KPCo's retentions. Coverage is generally provided by a combination of the protected cell of EIS and/or various industry mutual and/or commercial insurance carriers.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could have a material adverse effect on net income, cash flows and financial condition.

Environmental Settlement

In 1999, the Federal EPA, a number of states and certain special interest groups filed complaints alleging that certain of KPCo's affiliates including APCo, CSPCo, I&M and OPCo modified units at certain of their coal-fired generating plants in violation of the New Source Review (NSR) requirements of the Clean Air Act (CAA).

As part of a global consent decree covering all coal-fired units in the five eastern states of the AEP System to resolve all past NSR allegations and secure a covenant not to sue for future claims from the Federal EPA, KPCo agreed to complete previously announced flue gas desulfurization emissions control equipment (scrubbers) on Unit 2 of the Big Sandy Plant by December 2015. The obligation to pay a $15 million civil penalty and provide $36 million for environmental mitigation projects coordinated with the federal government and $24 million to the states for environmental mitigation was shared by members of the AEP Power Pool. Under the consent decree, KPCo recorded its share of the costs of $5.2 million in Other Operation expense in 2007.

Management believes KPCo can recover any capital and operating costs of additional pollution control equipment that may be required as a result of the consent decree through regulated rates or market prices of electricity. If KPCo is unable to recover such costs, it would adversely affect KPCo's future net income, cash flows and possibly financial condition.

Carbon Dioxide Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in Federal District Court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The trial court dismissed the lawsuits.

In September 2009, the Second Circuit Court of Appeals issued a ruling on appeal remanding the cases to the Federal District Court for the Southern District of New York. The Second Circuit held that the issues of climate change and global warming do not raise political questions and that Congress' refusal to regulate CO_2 emissions does not mean that plaintiffs must wait for an initial policy determination by Congress or the President's administration to secure the relief sought in their complaints. The court stated that Congress could enact comprehensive legislation to regulate CO_2 emissions or that the Federal EPA could regulate CO_2 emissions under existing CAA authorities and that either of these actions could override any decision made by the district court under federal common law. The Second Circuit did not rule on whether the plaintiffs could proceed with their state common law nuisance claims. In November 2009, the defendants filed for rehearing.

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 CO_2 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. KPCo was initially dismissed from this case without prejudice, but is named as a defendant in a pending fourth amended complaint.

Management believes the actions are without merit and intends to continue to defend against the claims.

Alaskan Villages' Claims

In 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil and gas companies, a coal company, and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of \$95 million to \$400 million. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. The plaintiffs appealed the decision. Management believes the action is without merit and intends to defend against the claims.

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

By-products from the generation of electricity include materials such as ash, slag and sludge. 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 (PCBs) and other hazardous and nonhazardous materials. KPCo currently incurs costs to dispose of these substances safely.

Superfund addresses clean-up of hazardous substances that have been released to the environment. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. At December 31, 2009, there is one site for which KPCo has received an information request which could lead to a Potentially Responsible Party designation. In the instance where KPCo has been named a defendant, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

Management evaluates the potential liability for each site separately, but several general statements can be made about potential future liability. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be small and often nonhazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named for each site and several of the parties are financially sound enterprises. At present, management's estimates do not anticipate material cleanup costs for identified sites.

Defective Environmental Equipment

As part of the AEP System's continuing environmental investment program, management chose to retrofit wet flue gas desulfurization systems on one unit of the Big Sandy Plant utilizing the jet bubbling reactor (JBR) technology. Contracts for the project have been temporarily suspended during the early development stage of the project. The retrofits on three units owned by KPCo's affiliates are operational. Due to unexpected operating results, management completed an extensive review of the design and manufacture of the JBR internal components. The review concluded that there are fundamental design deficiencies and that inferior and/or inappropriate materials were selected for the internal fiberglass components. Management initiated discussions with Black & Veatch, the original equipment manufacturer, to develop a repair or replacement corrective action plan. Management intends to pursue contractual and other legal remedies, if management is unable to resolve these issues with Black & Veatch. If KPCo is unsuccessful in obtaining reimbursement for the work required to remedy this situation, the cost of repair or replacement could have an adverse impact on construction costs, net income, cash flows and financial condition.

FERC Long-term Contracts

In 2002, the FERC held a hearing related to a complaint filed by Nevada Power Company and Sierra Pacific Power Company (the Nevada utilities). The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were "high-priced." The complaint alleged that KPCo and certain other AEP subsidiaries sold power at unjust and unreasonable prices because the market for power was allegedly dysfunctional at the time such contracts were executed. In September 2009, the parties reached a settlement. The settlement payment was made in February 2010.

5. BENEFIT PLANS

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Investments Held in Trust for Future Liabilities" and "Fair Value Measurements of Assets and Liabilities" sections of Note 1.

KPCo participates in an AEP sponsored qualified pension plan and two unfunded nonqualified pension plans. AEP merged two qualified plans at December 31, 2008. A substantial majority of employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. KPCo participates in OPEB plans sponsored by AEP to provide medical and life insurance benefits for retired employees.

KPCo recognizes its obligations associated with defined benefit pension plans and OPEB plans in its balance sheets at fair value under the "Fair Value Measurements and Disclosures" accounting guidance. Additional disclosures about the plans are required by "Compensation – Retirement Benefits" accounting guidance. KPCo recognizes an asset for a plan's overfunded status or a liability for a plan's underfunded status and recognizes as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. KPCo records a regulatory asset for qualifying benefit costs of regulated operations that for ratemaking purposes are deferred for future recovery.

Adjustment of pretax AOCI is required at the end of each year, for both underfunded and overfunded defined benefit pension and OPEB plans, to an amount equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction and deferred gains result in an AOCI equity addition. The year-end AOCI measure can be volatile based on fluctuating market conditions, investment returns and discount rates.

The following tables provide a reconciliation of the changes in projected benefit obligations and fair value of assets for AEP's plans over the two-year period ending at the plan's measurement date of December 31, 2009, and their funded status as of December 31 of each year:

Projected Plan Obligations, Plan Assets, Funded Status as of December 31, 2009 and 2008

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,		December 31,	
	2009	2008	2009	2008
Change in Projected Benefit Obligation	(in millions)			
Projected Obligation at January 1	$ 4,301	$ 4,109	$ 1,843	$ 1,773
Service Cost	104	100	42	42
Interest Cost	254	249	110	113
Actuarial Loss	290	139	32	2
Benefit Payments	(248)	(296)	(120)	(120)
Participant Contributions	-	-	25	24
Medicare Subsidy	-	-	9	9
Projected Obligation at December 31	$ 4,701	$ 4,301	$ 1,941	$ 1,843
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 3,161	$ 4,504	$ 1,018	$ 1,400
Actual Gain (Loss) on Plan Assets	482	(1,054)	235	(368)
Company Contributions	8	7	150	82
Participant Contributions	-	-	25	24
Benefit Payments	(248)	(296)	(120)	(120)
Fair Value of Plan Assets at December 31	$ 3,403	$ 3,161	$ 1,308	$ 1,018
Underfunded Status at December 31	$ (1,298)	$ (1,140)	$ (633)	$ (825)

Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions as of December 31 of each year used in the measurement of AEP's benefit obligations are shown in the following table:

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,		December 31,	
Assumptions	2009	2008	2009	2008
Discount Rate	5.60%	6.00%	5.85%	6.10%
Rate of Compensation Increase	4.60%(a)	5.90%(a)	N/A	N/A

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

N/A = Not Applicable

To determine a discount rate, AEP uses a duration-based method by constructing a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's Aa bond index with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2009, the rate of compensation increase assumed varies with the age of the employee, ranging from 3% per year to 11.5% per year, with an average increase of 4.6%.

Amounts Recognized on AEP's Balance Sheets as of December 31, 2009 and 2008

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,		December 31,	
	2009	2008	2009	2008
	(in millions)			
Other Current Liabilities – Accrued Short-term Benefit Liability	$ (10)	$ (9)	$ (4)	$ (4)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(1,288)	(1,131)	(629)	(821)
Underfunded Status	$ (1,298)	$ (1,140)	$ (633)	$ (825)

Amounts Recognized in AEP's Accumulated Other Comprehensive Income (AOCI) as of December 31, 2009, 2008 and 2007

	Pension Plans			Other Postretirement Benefit Plans		
	December 31,			December 31,		
	2009	2008	2007	2009	2008	2007
Components	(in millions)					
Net Actuarial Loss	$ 2,096	$ 2,024	$ 534	$ 546	$ 715	$ 231
Prior Service Cost	12	13	14	3	3	4
Transition Obligation	-	-	-	43	70	97
Pretax AOCI	$ 2,108	$ 2,037	$ 548	$ 592	$ 788	$ 332
Recorded as						
Regulatory Assets	$ 1,750	$ 1,660	$ 453	$ 380	$ 502	$ 204
Deferred Income Taxes	125	132	33	74	100	45
Net of Tax AOCI	233	245	62	138	186	83
Pretax AOCI	$ 2,108	$ 2,037	$ 548	$ 592	$ 788	$ 332

Components of the Change in AEP's Plan Assets and Benefit Obligations Recognized in Pretax AOCI during the years ended December 31, 2009 and 2008 are as follows:

	Pensions Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,		Years Ended December 31,	
Components	2009	2008	2009	2008
	(in millions)			
Actuarial Loss (Gain) During the Year	$ 130	$ 1,527	$ (127)	$ 492
Amortization of Actuarial Loss	(59)	(37)	(42)	(9)
Prior Service Credit	-	(1)	-	-
Amortization of Transition Obligation	-	-	(27)	(27)
Total Pretax AOCI Change for the Year	$ 71	$ 1,489	$ (196)	$ 456

Pension and Other Postretirement Plans' Assets

The value of AEP's pension plan's assets increased to $3.4 billion at December 31, 2009 from $3.2 billion at December 31, 2008. The qualified plan paid $240 million in benefits to plan participants during 2009 (nonqualified plans paid $8 million in benefits). The value of the OPEB plans' assets increased to $1.3 billion at December 31, 2009 from $1 billion at December 31, 2008. The OPEB plans paid $120 million in benefits to plan participants during 2009.

The following table presents the classification of pension plan assets within the fair value hierarchy at December 31, 2009:

Major Categories of Plan Assets	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 1,219	$ -	$ -	$ -	$ 1,219	35.8%
International	320	-	-	-	320	9.4%
Real Estate Investment Trusts	87	-	-	-	87	2.6%
Common Collective Trust – International	-	161	-	-	161	4.7%
Subtotal Equities	1,626	161	-	-	1,787	52.5%
Fixed Income:						
United States Government and Agency Securities	-	233	-	-	233	6.9%
Corporate Debt	-	831	-	-	831	24.4%
Foreign Debt	-	171	-	-	171	5.0%
State and Local Government	-	35	-	-	35	1.0%
Other – Asset Backed	-	27	-	-	27	0.8%
Subtotal Fixed Income	-	1,297	-	-	1,297	38.1%
Real Estate	-	-	90	-	90	2.7%
Alternative Investments	-	-	106	-	106	3.1%
Securities Lending	-	173	-	-	173	5.1%
Securities Lending Collateral (a)	-	-	-	(196)	(196)	(5.8)%
Cash and Cash Equivalents (b)	-	116	-	4	120	3.5%
Other – Pending Transactions and Accrued Income (c)	-	-	-	26	26	0.8%
Total	$ 1,626	$ 1,747	$ 196	$ (166)	$ 3,403	100.0%

(a) Amounts in "Other" column primarily represent an obligation to repay cash collateral received as part on the Security Lending Program.
(b) Amounts in "Other" column primarily represent foreign currency holdings.
(c) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table sets forth a reconciliation of changes in the fair value of real estate and alternative investments classified as Level 3 in the fair value hierarchy for the pension assets:

	Real Estate	Alternative Investments	Total Level 3
		(in millions)	
Balance as of January 1, 2009	$ 137	$ 106	$ 243
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	(47)	(14)	(61)
Relating to Assets Sold During the Period	-	1	1
Purchases and Sales	-	13	13
Transfers in and/or out of Level 3	-	-	-
Balance as of December 31, 2009	$ 90	$ 106	$ 196

The following table presents the classification of OPEB plan assets within the fair value hierarchy at December 31, 2009:

Major Categories of Plan Assets	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 343	$ -	$ -	$ -	$ 343	26.2%
International	375	-	-	-	375	28.7%
Common Collective Trust – International	-	93	-	-	93	7.1%
Subtotal Equities	718	93	-	-	811	62.0%
Fixed Income:						
Common Collective Trust – Debt	-	38	-	-	38	2.9%
United States Government and Agency Securities	-	42	-	-	42	3.2%
Corporate Debt	-	141	-	-	141	10.8%
Foreign Debt	-	32	-	-	32	2.4%
State and Local Government	-	6	-	-	6	0.5%
Other – Asset Backed	-	2	-	-	2	0.2%
Subtotal Fixed Income	-	261	-	-	261	20.0%
Trust Owned Life Insurance:						
International Equities	-	75	-	-	75	5.7%
United States Bonds	-	131	-	-	131	10.0%
Cash and Cash Equivalents (a)	7	14	-	1	22	1.7%
Other – Pending Transactions and Accrued Income (b)	-	-	-	8	8	0.6%
Total	$ 725	$ 574	$ -	$ 9	$ 1,308	100.0%

(a) Amounts in “Other” column primarily represent foreign currency holdings.
(b) Amounts in “Other” column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The asset allocations for AEP's plans at the end of 2008 by asset category, were as follows:

Asset Category	Percentage of Plan Assets at December 31, 2008 Pension Plans	Other Postretirement Benefit Plans
Equity Securities	47%	53%
Real Estate	6%	-
Debt Securities	42%	43%
Cash and Cash Equivalents	5%	4%
Total	100%	100%

Significant Concentrations of Risk Within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. AEP monitors the plan to control security diversification and ensure compliance with its investment policy. At December 31, 2009, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

Determination of Pension Expense

AEP bases its determination of pension expense or income on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded.

Accumulated Benefit Obligation	December 31, 2009	2008
	(in millions)	
Qualified Pension Plans	$ 4,539	$ 4,119
Nonqualified Pension Plans	90	80
Total	$ 4,629	$ 4,199

For the underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets of these plans at December 31, 2009 and 2008 were as follows:

	Underfunded Pension Plans December 31, 2009	2008
	(in millions)	
Projected Benefit Obligation	$ 4,701	$ 4,301
Accumulated Benefit Obligation	$ 4,629	$ 4,199
Fair Value of Plan Assets	3,403	3,161
Underfunded Accumulated Benefit Obligation	$ 1,226	$ 1,038

Estimated Future Benefit Payments and Contributions

AEP expects contributions and payments for the pension plans of $160 million and the OPEB plans of $117 million during 2010. The amount for the pension plans is at least the minimum amount required by the Employee Retirement Income Security Act of 1974, as amended plus payment of unfunded nonqualified benefits. For the qualified pension plan, AEP may make additional discretionary contributions to maintain the funded status of the plan. The contribution to the OPEB plans is generally based on the amount of the OPEB plans' periodic benefit costs for accounting purposes as provided for in agreements with state regulatory authorities, plus the additional discretionary contribution of the Medicare subsidy receipts.

The table below reflects the total benefits expected to be paid from the plan or from the employer's assets, including both the employer's share of the benefit cost and the participants' share of the cost, which is funded by participant contributions to the plan. Medicare subsidy receipts are shown in the year of the corresponding benefit payments, even though actual cash receipts are expected early in the following year. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for AEP's pension benefits and OPEB are as follows:

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	Benefit Payments	Medicare Subsidy Receipts
		(in millions)	
2010	$ 332	$ 119	$ (10)
2011	342	130	(11)
2012	348	139	(13)
2013	355	148	(14)
2014	358	158	(15)
Years 2015 to 2019, in Total	1,871	923	(95)

Components of Net Periodic Benefit Cost

The following table provides the components of AEP's net periodic benefit cost for the plans for the years ended December 31, 2009, 2008 and 2007:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2009	2008	2007	2009	2008	2007
			(in millions)			
Service Cost	$ 104	$ 100	$ 96	$ 42	$ 42	$ 42
Interest Cost	254	249	235	110	113	104
Expected Return on Plan Assets	(321)	(336)	(340)	(80)	(111)	(104)
Amortization of Transition Obligation	-	-	-	27	27	27
Amortization of Prior Service Cost	-	1	-	-	-	-
Amortization of Net Actuarial Loss	59	37	59	42	9	12
Net Periodic Benefit Cost	96	51	50	141	80	81
Capitalized Portion	(30)	(16)	(14)	(44)	(25)	(25)
Net Periodic Benefit Cost Recognized as Expense	$ 66	$ 35	$ 36	$ 97	$ 55	$ 56

Estimated amounts expected to be amortized to net periodic benefit costs for AEP's plans during 2010 are shown in the following table:

Components	**Pension Plans**	**Other Postretirement Benefit Plans**
	(in millions)	
Net Actuarial Loss	$ 99	$ 29
Prior Service Cost	1	-
Transition Obligation	-	27
Total Estimated 2010 Pretax AOCI Amortization	$ 100	$ 56
Expected to be Recorded as		
Regulatory Asset	$ 82	$ 37
Deferred Income Taxes	6	7
Net of Tax AOCI	12	12
Total	$ 100	$ 56

The following table provides KPCo's net periodic benefit cost for the plans for the years ended December 31, 2009, 2008 and 2007:

	Pension Plans			**Other Postretirement Benefit Plans**		
	Years Ended December 31,					
	2009	**2008**	**2007**	**2009**	**2008**	**2007**
	(in thousands)					
Benefit Costs	$ 2,218	$ 995	$ 1,018	$ 3,232	$ 1,618	$ 1,706

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions as of January 1 of each year used in the measurement of AEP's benefit costs are shown in the following tables:

	Pension Plans			**Other Postretirement Benefit Plans**		
	2009	**2008**	**2007**	**2009**	**2008**	**2007**
Discount Rate	6.00%	6.00%	5.75%	6.10%	6.20%	5.85%
Expected Return on Plan Assets	8.00%	8.00%	8.50%	7.75%	8.00%	8.00%
Rate of Compensation Increase	5.90%	5.90%	5.90%	N/A	N/A	N/A

N/A = Not Applicable

The expected return on plan assets for 2009 was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation and current prospects for economic growth.

The health care trend rate assumptions as of January 1 of each year used for OPEB plans measurement purposes are shown below:

Health Care Trend Rates	**2009**	**2008**
Initial	6.50%	7.00%
Ultimate	5.00%	5.00%
Year Ultimate Reached	2012	2012

Assumed health care cost trend rates have a significant effect on the amounts reported for the OPEB health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 20	$ (16)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	217	(180)

American Electric Power System Retirement Savings Plan

KPCo participates in an AEP sponsored defined contribution retirement savings plan, the American Electric Power System Retirement Savings Plan, for substantially all employees. This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for company matching contributions. The matching contributions to the plan was 75% of the first 6% of eligible compensation contributed by the employee in 2008. Effective January 1, 2009, the match is 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions. The cost for contributions to the plan totaled $1.7 million in 2009, $1.6 million in 2008 and $1.4 million in 2007.

6. BUSINESS SEGMENTS

KPCo has one reportable segment, an integrated electricity generation, transmission and distribution business. KPCo's other activities are insignificant.

7. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

KPCo is exposed to certain market risks as a power producer and marketer of wholesale electricity, coal and emission allowances. These risks include commodity price risk, interest rate risk and credit risk. These risks represent the risk of loss that may impact KPCo due to changes in the underlying market prices or rates. AEPSC, on behalf of KPCo, manages these risks using derivative instruments.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

The strategy surrounding the use of derivative instruments focuses on managing risk exposures, future cash flows and creating value based on open trading positions by utilizing both economic and formal hedging strategies. To accomplish these objectives, AEPSC, on behalf of KPCo, 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 KPCo, enters into electricity, coal, natural gas, interest rate and to a lesser degree heating oil, gasoline, emission allowance and other commodity contracts to manage the risk associated with the energy business. AEPSC, on behalf of KPCo, enters into interest rate derivative contracts in order to manage the interest rate exposure associated with KPCo's commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. AEPSC, on behalf of KPCo, also engages in risk management of interest rate risk associated with debt financing. The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with the established risk management policies as approved by the Finance Committee of AEP's Board of Directors.

The following table represents the gross notional volume of KPCo's outstanding derivative contracts as of December 31, 2009:

Notional Volume of Derivative Instruments
December 31, 2009

Primary Risk Exposure		Volume (in thousands)	Unit of Measure
Commodity:			
Power		38,509	MWHs
Coal		2,230	Tons
Natural Gas		3,600	MMBtus
Heating Oil and Gasoline		306	Gallons
Interest Rate	$	4,239	USD
Interest Rate	$	-	USD

Fair Value Hedging Strategies

At certain times, AEPSC, on behalf of KPCo, enters into interest rate derivative transactions in order to manage existing fixed interest rate risk exposure. These interest rate derivative transactions effectively modify KPCo's exposure to interest rate risk by converting a portion of KPCo's fixed-rate debt to a floating rate.

Cash Flow Hedging Strategies

AEPSC, on behalf of KPCo, enters into and designates as cash flow hedges certain derivative transactions for the purchase and sale of electricity, coal, heating oil and natural gas ("Commodity") in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. KPCo 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. KPCo does not hedge all commodity price risk.

KPCo's vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of KPCo, enters into financial gasoline and heating oil derivative contracts in order mitigate price risk of future fuel purchases. For disclosure purposes, these contracts are included with other hedging activity as "Commodity." KPCo does not hedge all of fuel price risk.

AEPSC, on behalf of KPCo, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. KPCo 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. KPCo does not hedge all interest rate exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON KPCo's FINANCIAL STATEMENTS

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities in the balance sheet at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, KPCo applies 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 KPCo's risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the December 31, 2009 and 2008 balance sheets, KPCo netted $800 thousand and $468 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $6.4 million and $1.2 million, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following table represents the gross fair value impact of KPCo's derivative activity on the Balance Sheet as of December 31, 2009.

Fair Value of Derivative Instruments
December 31, 2009

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate (a)**	**Other (a) (b)**	**Total**
			(in thousands)		
Current Risk Management Assets	$ 66,858	$ 748	$ -	$ (53,919)	$ 13,687
Long-term Risk Management Assets	26,571	-	-	(17,073)	9,498
Total Assets	93,429	748	-	(70,992)	23,185
Current Risk Management Liabilities	62,216	1,024	-	(58,050)	5,190
Long-term Risk Management Liabilities	23,879	16	-	(19,794)	4,101
Total Liabilities	86,095	1,040	-	(77,844)	9,291
Total MTM Derivative Contract Net Assets (Liabilities)	$ 7,334	$ (292)	$ -	$ 6,852	$ 13,894

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented in the Balance Sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts represent counterparty netting of risk management and hedging contracts, associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging" and dedesignated risk management contracts.

The table below presents KPCo's activity of derivative risk management contracts for the year ended December 31, 2009:

**Amount of Gain (Loss) Recognized on
Risk Management Contracts**

Location of Gain (Loss)	Year Ended December 31, 2009
	(in thousands)
Electric Generation, Transmission and Distribution Revenues	$ 20,402
Sales to AEP Affiliates	(2,162)
Regulatory Assets (a)	-
Regulatory Liabilities (a)	(2,719)
Total Gain on Risk Management Contracts	$ 15,521

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

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

KPCo's 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, KPCo 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. Realized gains and losses on derivative instruments held for trading purposes are included in Revenues on a net basis in KPCo's Statements of Income. Realized gains and losses on derivative instruments not held for trading purposes are included in Revenues or Expenses on KPCo's Statements of Income depending on the relevant facts and circumstances. Unrealized and realized gains and losses for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains), in accordance with the accounting guidance for "Regulated Operations."

Accounting for Fair Value Hedging Strategies

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof attributable to a particular risk), KPCo recognizes 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.

KPCo records realized 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 KPCo's Statements of Income. During 2009 and 2008, KPCo did not employ any fair value hedging strategies. During 2007, KPCo designated interest rate derivatives as fair value hedges.

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), KPCo initially reports the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the Balance Sheets until the period the hedged item affects Net Income. KPCo records hedge ineffectiveness as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivatives transactions for the purchase and sale of electricity, coal, heating oil and natural gas designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale in KPCo's Statements of Income, or in Regulatory Assets or Regulatory Liabilities on KPCo's Balance Sheet, depending on the specific nature of the risk being hedged. During 2009, 2008 and 2007, KPCo designated commodity derivatives as cash flow hedges.

Beginning in 2009, KPCo executed financial heating oil and gasoline derivative contracts to hedge the price risk of its diesel fuel and gasoline purchases. KPCo reclassifies gains and losses on financial fuel derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on its balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the Statements of Income. During 2009, KPCo designated cash flow hedging strategies of forecasted fuel purchases. This strategy was not active for KPCo during 2008 and 2007.

KPCo reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During 2009 and 2008, KPCo did not employ any cash flow hedging strategies for interest rates. During 2007, KPCo designated interest rate derivatives as cash flow hedges.

During 2009, 2008, and 2007, hedge ineffectiveness was immaterial or nonexistent for all hedge strategies disclosed above.

The following tables provide details on designated, effective cash flow hedges included in AOCI on KPCo's Balance Sheets and the reasons for changes in cash flow hedges for the year ended December 31, 2009. All amounts in the following table are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges

For the Year Ended December 31, 2009

	Commodity	Interest Rate	Total
		(in thousands)	
Beginning Balance in AOCI as of January 1, 2009	$ 584	$ (525)	$ 59
Changes in Fair Value Recognized in AOCI	(152)	-	(152)
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:			
Electric Generation, Transmission and Distribution Revenues	(1,564)	-	(1,564)
Fuel and Other Consumables Used for Electric Generation	(23)	-	(23)
Purchased Electricity for Resale	1,032	-	1,032
Interest Expense	-	62	62
Property, Plant and Equipment	(15)	-	(15)
Ending Balance in AOCI as of December 31, 2009	$ (138)	$ (463)	$ (601)

During 2008 and 2007, KPCo reclassified $320 thousand of gains and $1.3 million of losses, respectively, from AOCI to net income.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's Balance Sheet at December 31, 2009 were:

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2009

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ 422	$ -	$ 422
Hedging Liabilities (a)	(714)	-	(714)
AOCI Loss Net of Tax	(138)	(463)	(601)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(127)	(60)	(187)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on KPCo's Balance Sheet.

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of December 31, 2009, the maximum length of time that KPCo is hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") exposure to variability in future cash flows related to forecasted transactions is 14 months.

Credit Risk

Management limits credit risk in KPCo's 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. KPCo uses Moody's, S&P and current market-based qualitative and quantitative data to assess the financial health of counterparties on an ongoing basis. If an external rating is not available, an internal rating is generated utilizing a quantitative tool developed by Moody's to estimate probability of default that corresponds to an implied external agency credit rating.

KPCo 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), KPCo is 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 believes that a downgrade below investment grade is unlikely. As of December 31, 2009, the aggregate value of such derivative contracts was $449 thousand and KPCo was not required to post any cash collateral. KPCo would have been required to post $1.7 million of collateral at December 31, 2009 for all derivative and non-derivative contracts if certain credit ratings had declined below investment grade of which $1.6 million was attributable to RTO and ISO activities.

In addition, a majority of KPCo's 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 borrowed 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. As of December 31, 2009, the fair value of derivative liabilities subject to cross-default provisions totaled $31 million prior to consideration of contractual netting arrangements. This exposure has been reduced by cash collateral posted of $628 thousand. Management believes that a non-performance event under these provisions is unlikely. If a cross-default provision would have been triggered, a settlement of up to $7 million would be required after considering KPCo's contractual netting arrangements.

8. FAIR VALUE MEASUREMENTS

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 KPCo's Long-term Debt at December 31, 2009 and 2008 are summarized in the following table:

	December 31,			
	2009		2008	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 548,722	$ 599,909	$ 418,555	$ 366,108

Fair Value Measurements of Financial Assets and Liabilities

For a discussion of fair value accounting and the classification of assets and liabilities within the fair value hierarchy, see "Fair Value Measurements of Assets and Liabilities" section of Note 1.

The following tables set forth, by level within the fair value hierarchy, KPCo's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2009 and 2008. 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 as of December 31, 2009

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Contracts (a)	$ 472	$ 90,327	$ 2,592	$ (72,387)	$ 21,004
Cash Flow and Fair Value Hedges (a)	-	748	-	(326)	422
Dedesignated Risk Management Contracts (b)	-	-	-	1,759	1,759
Total Risk Management Assets	$ 472	$ 91,075	$ 2,592	$ (70,954)	$ 23,185
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 533	$ 84,831	$ 693	$ (78,030)	$ 8,027
Cash Flow and Fair Value Hedges (a)	-	1,040	-	(326)	714
DETM Assignment (c)	-	-	-	550	550
Total Risk Management Liabilities	$ 533	$ 85,871	$ 693	$ (77,806)	$ 9,291

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of December 31, 2008

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Contracts (a)	$ 3,443	$ 140,387	$ 2,561	$ (125,636)	$ 20,755
Cash Flow and Fair Value Hedges (a)	-	1,418	-	(302)	1,116
Dedesignated Risk Management Contracts (b)	-	-	-	2,749	2,749
Total Risk Management Assets	$ 3,443	$ 141,805	$ 2,561	$ (123,189)	$ 24,620
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 4,021	$ 132,087	$ 848	$ (126,370)	$ 10,586
Cash Flow and Fair Value Hedges (a)	-	544	-	(302)	242
DETM Assignment (c)	-	-	-	1,118	1,118
Total Risk Management Liabilities	$ 4,021	$ 132,631	$ 848	$ (125,554)	$ 11,946

(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) “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 MTM value will be amortized into revenues over the remaining life of the contracts.

(c) See “Natural Gas Contracts with DETM” section of Note 12.

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:

	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of January 1, 2009	$ 1,713
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(283)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	(1,118)
Transfers in and/or out of Level 3 (d)	(103)
Changes in Fair Value Allocated to Regulated Jurisdictions (e)	1,690
Balance as of December 31, 2009	$ 1,899

	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of January 1, 2008	$ (157)
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)	95
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements	-
Transfers in and/or out of Level 3 (d)	(192)
Changes in Fair Value Allocated to Regulated Jurisdictions (e)	1,967
Balance as of December 31, 2008	$ 1,713

(a) Included in revenues on KPCo's 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 commodity contracts for the reporting period.
(d) 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.
(e) Relates to the net gains (losses) of those contracts that are not reflected on the Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities.

9. INCOME TAXES

The details of income taxes as reported are as follows:

	Year Ended December 31, 2009	2008	2007
		(in thousands)	
Income Tax Expense (Credit):			
Current	$ (40,140)	$ 4,674	$ 11,258
Deferred	50,612	4,097	5,691
Deferred Investment Tax Credits	(822)	(875)	(962)
Total Income Taxes	$ 9,650	$ 7,896	$ 15,987

Shown below is a reconciliation of the difference between the amount of federal income taxes computed by multiplying book income before income taxes by the federal statutory rate and the amount of income taxes reported.

	Year Ended December 31, 2009	2008	2007
		(in thousands)	
Net Income	$ 23,936	$ 24,531	$ 32,470
Income Taxes	9,650	7,896	15,987
Pretax Income	$ 33,586	$ 32,427	$ 48,457
Income Tax on Pretax Income at Statutory Rate (35%)	$ 11,755	$ 11,349	$ 16,960
Increase (Decrease) in Income Tax resulting from the following items:			
Depreciation	2,256	1,169	1,223
Allowance for Funds Used During Construction	(626)	(872)	(661)
Removal Costs	(1,465)	(4,110)	(1,766)
Investment Tax Credits, Net	(822)	(875)	(962)
State and Local Income Taxes	(2,938)	1,072	736
Other	1,490	163	457
Total Income Taxes	$ 9,650	$ 7,896	$ 15,987
Effective Income Tax Rate	28.7%	24.4%	33.0%

The following table shows elements of the net deferred tax liability and significant temporary differences:

	December 31, 2009	2008
	(in thousands)	
Deferred Tax Assets	$ 29,427	$ 56,519
Deferred Tax Liabilities	(341,896)	(312,433)
Net Deferred Tax Liabilities	$ (312,469)	$ (255,914)
Property Related Temporary Differences	$ (234,969)	$ (203,951)
Amounts Due From Customers For Future Federal Income Taxes	(27,057)	(27,299)
Deferred State Income Taxes	(36,564)	(29,694)
Revenue Refunds	850	7,125
Deferred Storm Damage	(8,524)	-
Deferred Income Taxes on Other Comprehensive Loss	324	(32)
Accrued Pensions	9,994	8,959
Mark-to-Market	(4,088)	(716)
All Other, Net	(12,435)	(10,306)
Net Deferred Tax Liabilities	$ (312,469)	$ (255,914)

KPCo joins in the filing of a consolidated federal income tax return with its 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.

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2001. KPCo and other AEP 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, KPCo accrues 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.

KPCo, along with other AEP subsidiaries, files income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns and KPCo and other AEP 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, KPCo is no longer subject to state or local income tax examinations by tax authorities for years before 2000.

KPCo sustained federal, state and local net income tax operating losses in 2009 driven primarily by bonus depreciation, a change in tax accounting method related to units of property and other book versus tax temporary differences. As a result, KPCo accrued current federal, state and local income tax benefits in 2009. There is sufficient capacity in prior periods to carry the consolidated federal net operating loss back. The preponderance of the state and local jurisdictions do not provide for a net operating loss carry back, however it is anticipated that future taxable income will be sufficient to realize the tax benefit. As such, management has determined that a valuation allowance is unnecessary.

KPCo recognizes interest accruals related to uncertain tax positions in interest income or expense as applicable, and penalties in Other Operation in accordance with the accounting guidance for "Income Taxes."

The following table shows amounts reported for interest expense, interest income and reversal of prior period interest expense:

	Years Ended December 31, 2009	2008	2007
		(in thousands)	
Interest Expense	$ 1,113	$ 303	$ 55
Interest Income	-	1,863	-
Reversal of Prior Period Interest Expense	39	-	926

The following table shows balances for amounts accrued for the receipt of interest and the payment of interest and penalties:

	December 31, 2009	2008
	(in thousands)	
Accrual for Receipt of Interest	$ 416	$ 1,716
Accrual for Payment of Interest and Penalties	722	788

The reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2009	2008	2007
		(in thousands)	
Balance at January 1,	$ 3,345	$ 2,205	$ 3,413
Increase - Tax Positions Taken During a Prior Period	2,178	-	1
Decrease - Tax Positions Taken During a Prior Period	(2,757)	(113)	(1,796)
Increase - Tax Positions Taken During the Current Year	-	1,301	587
Decrease - Tax Positions Taken During the Current Year	(141)	(144)	-
Increase - Settlements with Taxing Authorities	-	96	-
Decrease - Lapse of the Applicable Statute of Limitations	(72)	-	-
Balance at December 31,	$ 2,553	$ 3,345	$ 2,205

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $528 thousand. Management believes there will be no significant net increase or decrease in unrecognized tax benefits within 12 months of the reporting date.

Federal Tax Legislation

Several tax bills and other legislation with tax-related sections were enacted in 2007 and 2008, including the Tax Technical Corrections Act of 2007, the Tax Increase Prevention Act of 2007, the Energy Independence and Security Act of 2007 and the Emergency Economic Stabilization Act of 2008. These tax law changes enacted in 2007 and 2008 did not materially affect KPCo's net income, cash flows or financial condition.

The Economic Stimulus Act of 2008 provided enhanced expensing provisions for certain assets placed in service in 2008 and a 50% bonus depreciation provision similar to the one in effect in 2003 through 2004 for assets placed in service in 2008. The enacted provisions did not have a material impact on net income or financial condition, but provided a material favorable cash flow benefit of approximately $10 million.

The American Recovery and Reinvestment Tax Act of 2009 provided for several new grant programs and expanded tax credits and an extension of the 50% bonus depreciation provision enacted in the Economic Stimulus Act of 2008. The enacted provisions did not have a material impact on KPCo's net income or financial condition. However, the bonus depreciation contributed to AEP's 2009 federal net operating tax loss and will result in a future cash flow benefit to KPCo.

State Tax Legislation

Michigan Senate Bill 0094 (MBT Act), effective January 1, 2008, provided a comprehensive restructuring of Michigan's principal business tax. The law replaced the Michigan Single Business Tax. The MBT Act is composed of a new tax which will be calculated based upon two components: (a) a business income tax (BIT) imposed at a rate of 4.95% and (b) a modified gross receipts tax (GRT) imposed at a rate of 0.80%, which will collectively be referred to as the BIT/GRT tax calculation. The law also includes significant credits for engaging in Michigan-based activity.

In September 2007, House Bill 5198 amended the MBT Act to provide for a new deduction on the BIT and GRT tax returns equal to the book-tax basis difference triggered as a result of the enactment of the MBT Act. This state-only temporary difference will be deducted over a 15-year period on the MBT Act tax returns starting in 2015. Management has evaluated the impact of the MBT Act and the application of the MBT Act will not materially affect KPCo's net income, cash flows or financial condition.

In March 2008, legislation was signed providing for, among other things, a reduction in the West Virginia corporate income tax rate from 8.75% to 8.5% beginning in 2009. The corporate income tax rate could also be reduced to 7.75% in 2012 and 7% in 2013 contingent upon the state government achieving certain minimum levels of shortfall reserve funds. Management has evaluated the impact of the law change and the application of the law change will not materially impact KPCo's net income, cash flows or financial condition.

10. LEASES

Leases of property, plant and equipment are for periods up to 20 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. The components of rental costs are as follows:

	Years Ended December 31,		
Lease Rental Costs	**2009**	**2008**	**2007**
		(in thousands)	
Net Lease Expense on Operating Leases	$ 1,948	$ 2,250	$ 2,405
Amortization of Capital Leases	746	971	1,141
Interest on Capital Leases	53	102	140
Total Lease Rental Costs	$ 2,747	$ 3,323	$ 3,686

The following table shows the property, plant and equipment under capital leases and related obligations recorded on KPCo's Balance Sheets. Capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities on KPCo's Balance Sheets.

	December 31, 2009	December 31, 2008
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Production	$ 504	$ -
Other Property, Plant and Equipment	2,876	3,974
Total Property, Plant and Equipment Under Capital Leases	3,380	3,974
Accumulated Amortization	1,627	2,152
Net Property, Plant and Equipment Under Capital Leases	$ 1,753	$ 1,822
Obligations Under Capital Leases		
Noncurrent Liability	$ 1,113	$ 1,045
Liability Due Within One Year	640	777
Total Obligations Under Capital Leases	$ 1,753	$ 1,822

Future minimum lease payments consisted of the following at December 31, 2009:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2010	$ 703	$ 2,019
2011	588	4,677
2012	134	858
2013	132	510
2014	105	35
Later Years	344	125
Total Future Minimum Lease Payments	$ 2,006	$ 8,224
Less Estimated Interest Element	253	
Estimated Present Value of Future Minimum Lease Payments	$ 1,753	

Master Lease Agreements

KPCo leases 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, KPCo 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. As a result, the unamortized value of this equipment of $4 million is reflected in KPCo's future minimum lease payments for 2011. In December 2008 and 2009, management signed new master lease agreements with one-year commitment periods 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 market value of the leased equipment is below the unamortized balance at the end of the lease term, KPCo is committed to pay the difference between the fair market 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 market value of the leased equipment is below the guaranteed residual value at the end of the lease term, KPCo is committed to pay the difference between the actual fair market value and the residual value guarantee. At December 31, 2009, the maximum potential loss for these lease agreements was approximately $865 thousand assuming the fair market value of the equipment is zero at the end of the lease term. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance.

11. FINANCING ACTIVITIES

Long-term Debt

There are certain limitations on establishing liens against KPCo's assets under its indentures. None of the long-term debt obligations of KPCo have been guaranteed or secured by AEP or any of its affiliates.

The following details long-term debt outstanding as of December 31, 2009 and 2008:

Type of Debt	Maturity	Weighted Average Interest Rate at December 31, 2009	Interest Rate Ranges at December 31, 2009	Interest Rate Ranges at December 31, 2008	Outstanding at December 31, 2009	Outstanding at December 31, 2008
					(in thousands)	
Senior Unsecured Notes	2017-2039	6.40%	5.625%-8.13%	5.625%-6.00%	$ 530,000	$ 400,000
Notes Payable – Affiliated	2015	5.25%	5.25%	5.25%	20,000	20,000
Unamortized Discount					(1,278)	(1,445)
Total Long-term Debt					548,722	418,555
Less: Long-term Debt Due Within One Year					-	-
Long-term Debt					$ 548,722	$ 418,555

Long-term debt outstanding at December 31, 2009 is payable as follows:

	2010	2011	2012	2013	2014	After 2014	Total
				(in thousands)			
Principal Amount	$ -	$ -	$ -	$ -	$ -	$ 550,000	$ 550,000
Unamortized Discount							(1,278)
Total Long-term Debt							$ 548,722

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 borrowings from the Utility Money Pool as of December 31, 2009 and 2008 are included in Advances from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the years ended December 31, 2009 and 2008 are described in the following table:

Year	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Borrowings from Utility Money Pool as of December 31,	Authorized Short-Term Borrowing Limit
			(in thousands)			
2009	$ 174,108	$ 19,775	$ 113,764	$ 7,589	$ 485	$ 250,000
2008	142,416	-	54,536	-	131,399	250,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool for the years ended December 31, 2009, 2008 and 2007 are summarized in the following table:

Year Ended December 31,	Maximum Interest Rates for Funds Borrowed from the Utility Money Pool	Minimum Interest Rates for Funds Borrowed from the Utility Money Pool	Maximum Interest Rates for Funds Loaned to the Utility Money Pool	Minimum Interest Rates for Funds Loaned to the Utility Money Pool	Average Interest Rates for Funds Borrowed from the Utility Money Pool	Average Interest Rates for Funds Loaned to the Utility Money Pool
2009	2.28%	0.18%	0.63%	0.15%	1.33%	0.35%
2008	5.47%	2.28%	-%	-%	3.42%	-%
2007	5.92%	5.29%	5.94%	5.16%	5.50%	5.58%

Interest expense and interest income related to the Utility Money Pool are included in Interest Expense and Interest Income, respectively, in KPCo's Statements of Income. For amounts borrowed from and advanced to the Utility Money Pool, KPCo incurred the following amounts of interest expense and earned the following amounts of interest income, respectively, for the years ended December 31, 2009, 2008 and 2007:

	Years Ended December 31, 2009	2008	2007
		(in thousands)	
Interest Expense	$ 983	$ 1,893	$ 2,494
Interest Income	18	-	1,614

Dividend Restrictions

Federal Power Act

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

Leverage Restrictions

Pursuant to credit agreement leverage restrictions, as of December 31, 2009, none of the retained earnings of KPCo have restrictions related to the payment of dividends.

Credit Facilities

KPCo and certain other companies in the AEP System have a $627 million 3-year credit agreement. Under the facility, letters of credit may be issued. As of December 31, 2009, there were no outstanding amounts for KPCo under the facility. KPCo and certain other companies in the AEP System had a $350 million 364-day credit agreement that expired in April 2009.

Sale of Receivables – AEP Credit

AEP Credit has a sale of receivables agreement with bank conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires from affiliated utility subsidiaries to the bank conduits and receives cash. This transaction constitutes a sale of receivables in accordance with the accounting guidance for "Transfers and Servicing," allowing the receivables to be removed from AEP Credit's balance sheet and allowing AEP Credit to repay any debt obligations. AEP has no ownership interest in the bank conduits and is not required to consolidate these entities in accordance with GAAP. AEP Credit continues to service the receivables. This off-balance sheet transaction was entered into to allow AEP Credit to repay its outstanding debt obligations, continue to purchase the AEP operating companies' receivables, and accelerate AEP Credit's cash collections.

In July 2009, AEP renewed and increased its sale of receivables agreement with AEP Credit. The sale of receivables agreement provides a commitment of $750 million from bank conduits to purchase receivables from AEP Credit. This agreement will expire in July 2010. AEP intends to extend or replace the sale of receivables agreement. The previous sale of receivables agreement provided a commitment of $700 million. As of December 31, 2009, AEP Credit had $631 million of these receivable sales outstanding. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts. AEP Credit purchases accounts receivable through a purchase agreement with KPCo.

Comparative accounts receivable information for AEP Credit is as follows:

	Years Ended December 31, 2009	2008	2007
		($ in millions)	
Proceeds from Sale of Accounts Receivable	$ 7,043	$ 7,717	$ 6,970
Loss on Sale of Accounts Receivable	$ 3	$ 20	$ 33
Average Variable Discount Rate	0.57%	3.19%	5.39%

	December 31, 2009	2008
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 160	$ 118
Deferred Revenue from Servicing Accounts Receivable	1	1
Retained Interest if 10% Adverse Change in Uncollectible Accounts	158	116
Retained Interest if 20% Adverse Change in Uncollectible Accounts	156	114

Historical loss and delinquency amounts for the AEP System's customer accounts receivable managed portfolio is as follows:

	December 31, 2009	2008
	(in millions)	
Customer Accounts Receivable Retained	$ 492	$ 569
Accrued Unbilled Revenues Retained	503	449
Miscellaneous Accounts Receivable Retained	92	90
Allowance for Uncollectible Accounts Retained	(37)	(42)
Total Net Balance Sheet Accounts Receivable	1,050	1,066
Customer Accounts Receivable Securitized	631	650
Total Accounts Receivable Managed	$ 1,681	$ 1,716
Net Uncollectible Accounts Written Off	$ 33	$ 37

Customer accounts receivable retained and securitized for the electric operating companies are managed by AEP Credit. Miscellaneous accounts receivable have been fully retained and not securitized.

Delinquent customer accounts receivable for the electric utility affiliates that AEP Credit currently factors were $29 million and $22 million at December 31, 2009 and 2008, respectively. AEP Credit's delinquent customer accounts receivable represents accounts greater than 30 days past due.

Under the factoring arrangement, KPCo sells, without recourse, certain of its customer accounts receivable and accrued unbilled revenue balances to AEP Credit and is charged a fee based on AEP Credit financing costs, its uncollectible accounts experience for their receivables and administrative costs. The costs of factoring customer accounts receivable are reported in Other Operation of the KPCo's Statements of Income.

KPCo's factored accounts receivable and accrued unbilled revenues were $41 million and $56 million as of December 31, 2009 and 2008, respectively.

KPCo paid fees to AEP Credit for factoring customer accounts receivable of $2 million, $3 million and $4 million for the years ended December 31, 2009, 2008 and 2007, respectively.

12. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "Utility Money Pool – AEP System" and "Sale of Receivables – AEP Credit" sections of Note 11.

AEP Power Pool

APCo, CSPCo, I&M, KPCo and OPCo are parties to the Interconnection Agreement, dated July 6, 1951, as amended, defining how they share the costs and benefits associated with their generating plants. This sharing is based upon each company's member load ratio, which is calculated monthly on the basis of each company's maximum peak demand in relation to the sum of the maximum peak demands of all five companies during the preceding 12 months. In addition, since 1995, APCo, CSPCo, I&M, KPCo and OPCo have been parties to the AEP System Interim Allowance Agreement, which provides, among other things, for the transfer of SO_2 allowances associated with the transactions under the Interconnection Agreement.

Power, gas and risk management activities are conducted by AEPSC and profits and losses are allocated under the SIA to AEP Power Pool members, PSO and SWEPCo. Risk management activities involve the purchase and sale of electricity and gas under physical forward contracts at fixed and variable prices. In addition, the risk management of electricity, and to a lesser extent gas contracts, includes exchange traded futures and options and OTC options and swaps. The majority of these transactions represent physical forward contracts in the AEP System's traditional marketing area and are typically settled by entering into offsetting contracts. In addition, AEPSC enters into transactions for the purchase and sale of electricity and gas options, futures and swaps, and for the forward purchase and sale of electricity outside of the AEP System's traditional marketing area.

CSW Operating Agreement

PSO, SWEPCo and AEPSC are parties to a Restated and Amended Operating Agreement originally dated as of January 1, 1997 (CSW Operating Agreement), which was approved by the FERC. The CSW Operating Agreement requires PSO and SWEPCo to maintain adequate annual planning reserve margins and requires that capacity in excess of the required margins be made available for sale to other operating companies as capacity commitments. Parties are compensated for energy delivered to recipients based upon the deliverer's incremental cost plus a portion of the recipient's savings realized by the purchaser that avoids the use of more costly alternatives. Revenues and costs arising from third party sales are generally shared based on the amount of energy PSO or SWEPCo contributes that is sold to third parties.

System Integration Agreement (SIA)

The SIA provides for the integration and coordination of AEP East companies' and AEP West companies' zones. This includes joint dispatch of generation within the AEP System and the distribution, between the two zones, of costs and benefits associated with the transfers of power between the two zones (including sales to third parties and risk management and trading activities). The SIA is designed to function as an umbrella agreement in addition to the Interconnection Agreement and the CSW Operating Agreement, each of which controls the distribution of costs and benefits within a zone.

Power generated, allocated or provided under the Interconnection Agreement or CSW Operating Agreement is primarily sold to customers at rates approved by the public utility commission in the jurisdiction of sale.

Under both the Interconnection Agreement and CSW Operating Agreement, power generated that is not needed to serve the AEP System's native load is sold in the wholesale market by AEPSC on behalf of the generating subsidiary.

Affiliated Revenues and Purchases

The following table shows the revenues derived from sales to the pools, direct sales to affiliates, natural gas contracts with AEPES and other revenues for the years ended December 31, 2009, 2008 and 2007:

Related Party Revenues	2009	2008	2007
		(in thousands)	
Sales to AEP Power Pool	$ 64,074	$ 62,642	$ 56,708
Direct Sales to West Affiliates	454	3,521	3,738
Natural Gas Contracts with AEPES	(1,823)	(133)	(197)
Other	(92)	219	302
Total Revenues	$ 62,613	$ 66,249	$ 60,551

The following table shows the purchased power expense incurred from purchases from the pools and affiliates for the years ended December 31, 2009, 2008 and 2007:

Related Party Purchases	2009	2008	2007
		(in thousands)	
Purchases from AEP Power Pool	$ 96,284	$ 127,669	$ 96,997
Direct Purchases from East Affiliates	101,731	106,256	88,051
Direct Purchases from West Affiliates	305	454	351
Total Purchases	$ 198,320	$ 234,379	$ 185,399

The above summarized related party revenues and expenses are reported as Sales to AEP Affiliates and Purchased Electricity from AEP Affiliates on KPCo's Statements of Income.

System Transmission Integration Agreement

AEP's System Transmission Integration Agreement provides for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEP East companies' and AEP West companies' zones. Similar to the SIA, the System Transmission Integration Agreement functions as an umbrella agreement in addition to the Transmission Agreement (TA) and the Transmission Coordination Agreement (TCA). The System Transmission Integration Agreement contains two service schedules that govern:

- The allocation of transmission costs and revenues and
- The allocation of third-party transmission costs and revenues and AEP System dispatch costs.

The System Transmission Integration Agreement anticipates that additional service schedules may be added as circumstances warrant.

APCo, CSPCo, I&M, KPCo and OPCo are parties to the TA, dated April 1, 1984, as amended, defining how they share the costs associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345 kV and above) and certain facilities operated at lower voltages (138 kV and above). Like the Interconnection Agreement, this sharing is based upon each company's member load ratio.

KPCo's net credits as allocated under the TA during the years ended December 31, 2009, 2008 and 2007 were $9 million, $2 million and $800 thousand, respectively, and were recorded in Other Operation on KPCo's Statements of Income.

PSO, SWEPCo, TCC, TNC and AEPSC are parties to the TCA, originally dated January 1, 1997. The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with overseeing the coordinated planning of the transmission facilities of the AEP West companies.

Natural Gas Contracts with DETM

In 2003, AEPES assigned to AEPSC, as agent for the AEP East companies, approximately $97 million (negative value) associated with its natural gas contracts with DETM. The assignment was executed in order to consolidate DETM positions within AEP. Beginning in 2007, PSO and SWEPCo were allocated a portion of the DETM assignment based on the SIA methodology of sharing trading and marketing margins between the AEP East companies, PSO and SWEPCo. Concurrently, in order to ensure that there would be no financial impact to the AEP East companies, PSO or SWEPCo as a result of the assignment, AEPES and AEPSC entered into agreements requiring AEPES to reimburse AEPSC for any related cash settlements and all income related to the assigned contracts. KPCo's risk management liabilities related to DETM at December 31, 2009 and 2008 were $550 thousand and $1.1 million, respectively.

Fuel Agreement between OPCo and AEPES

OPCo and National Power Cooperative, Inc (NPC) have an agreement whereby OPCo operates a 500 MW gas plant owned by NPC (Mone Plant). AEPES entered into a fuel management agreement with OPCo and NPC to manage and procure fuel for the Mone Plant. The gas purchased by AEPES and used in generation is first sold to OPCo then allocated to the AEP East companies, who have an agreement to purchase 100% of the available generating capacity from the plant through May 2012. KPCo's related purchases of gas managed by AEPES were $88 thousand, $257 thousand and $930 thousand for the years ended December 31, 2009, 2008 and 2007, respectively. These purchases are reflected in Purchased Electricity for Resale on KPCo's Statements of Income.

Unit Power Agreements (UPA)

A UPA between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant unless it is sold to another utility. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) net of amounts received by AEGCo from any other sources, sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The I&M Power Agreement will continue in effect until the expiration of the lease term of Unit 2 of the Rockport Plant unless extended in specified circumstances.

Pursuant to an assignment between I&M and KPCo, and a UPA between KPCo and AEGCo, AEGCo sells KPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo has agreed to pay to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KPCo UPA ends in December 2022.

I&M Barging, Urea Transloading and Other Services

I&M provides barging, urea transloading and other transportation services to affiliates. Urea is a chemical used to control NO_x emissions at certain generation plants in the AEP System. KPCo recorded costs of $112 thousand, $9 thousand and $80 thousand in 2009, 2008 and 2007, respectively, for urea transloading provided by I&M. These costs were recorded as fuel expense or operation expense.

Central Machine Shop

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. APCo defers on its balance sheet the cost of performing the services, then transfers the cost to the affiliate for reimbursement. KPCo recorded these billings as capital or maintenance expense depending on the nature of the services received. These billings are recoverable from customers. KPCo's billed amounts were $358 thousand, $1.2 million and $167 thousand for the years ended December 31, 2009, 2008 and 2007, respectively.

Affiliate Coal Purchases

In 2008, OPCo entered into contracts to sell excess coal purchases to certain AEP subsidiaries through 2010. KPCo's purchases are reflected in Sales to AEP Affiliates on its Statements of Income. KPCo's realized and unrealized losses recorded for the years ended December 31, 2009 and 2008 were $340 thousand and $36 thousand, respectively.

Affiliate Railcar Agreement

KPCo has an agreement providing for the use of affiliates' leased or owned railcars when available. The agreement specifies that the company using the railcar will be billed, at cost, by the company furnishing the railcar. KPCo records these costs or reimbursements as costs or reduction of costs, respectively, in Fuel on its Balance Sheets and such costs are recoverable from customers. The following table shows the net effect of the railcar agreement on KPCo's Balance Sheets:

Billing Company	December 31, 2009	December 31, 2008
	(in thousands)	
APCo	$ 669	$ 274
OPCo	13	332

AEP Power Pool Purchases from OVEC

Beginning in 2006, the AEP Power Pool began purchasing power from OVEC as part of wholesale marketing and risk management activity. These purchases are reflected in Electric Generation, Transmission and Distribution revenues in KPCo's Statements of Income. The agreement ended in December 2008. KPCo recorded $4 million and $2 million for the years ended December 31, 2008 and 2007, respectively.

Sales and Purchases of Property

KPCo had affiliated sales and purchases of electric property individually amounting to $100 thousand or more for the years ended December 31, 2009, 2008 and 2007 as shown in the following table:

Companies	Years Ended December 31, 2009	2008	2007
		(in thousands)	
I&M to KPCo	$ -	$ 444	$ -
OPCo to KPCo	-	-	133

In addition, KPCo had aggregate affiliated sales and purchases of meters and transformers for the years ended December 31, 2009, 2008 and 2007 as shown in the following table:

	APCo	CSPCo	I&M	KGPCo	OPCo	PSO	SWEPCo	TCC	WPCo	Total
Sales					(in thousands)					
2009	$ 505	$ 23	$ 64	$ 7	$ 133	$ 3	$ 8	$ -	$ 1	$ 744
2008	354	11	16	6	121	-	2	33	-	543
2007	345	38	21	10	124	85	7	-	66	696
Purchases										
2009	$ 161	$ -	$ 50	$ -	$ 87	$ -	$ 26	$ -	$ -	$ 324
2008	112	-	15	-	95	-	-	-	-	222
2007	518	6	4	1	197	-	-	-	5	731

The amounts above are recorded in Property, Plant and Equipment. Transfers are performed at cost.

Global Borrowing Notes

AEP issued long-term debt, a portion of which was loaned to KPCo. The debt is reflected in Long-term Debt – Affiliated on KPCo's Balance Sheets. AEP pays the interest on the global notes, but KPCo accrues interest for its share of the global borrowing and remits the interest to AEP. The accrued interest is reflected in Accrued Interest on KPCo's Balance Sheets. KPCo participated in the global borrowing arrangement during the reporting periods.

Intercompany Billings

KPCo performs certain utility services for other AEP subsidiaries when necessary or practical. The costs of these services are billed on a direct-charge basis, whenever possible, or on reasonable bases of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital. Billings are capitalized or expensed depending on the nature of the services rendered.

Variable Interest Entities

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers risk absorption of a variable interest entity (VIE), also referred to as variability. Entities are required to consolidate a VIE when it is determined that they are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether KPCo is the primary beneficiary of a VIE, management considers factors such as equity at risk, the amount of the VIE's variability KPCo absorbs, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE and other factors. Management believes that the significant assumptions and judgments were applied consistently. There have been no changes to the reporting of VIEs in the financial statements where it is concluded that KPCo is the primary beneficiary. In addition, KPCo has not provided financial or other support to any VIE that was not previously contractually required.

KPCo holds a significant variable interest in AEPSC and AEGCo. AEPSC provides certain managerial and professional services to KPCo. AEP is the sole equity owner of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to KPCo and other AEP subsidiaries at AEPSC's cost. KPCo and other AEP subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. The cost reimbursement nature of AEPSC finances its operations. There are no other terms or arrangements between AEPSC and KPCo and other AEP subsidiaries that could require additional financial support from KPCo and other AEP subsidiaries or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. KPCo and other AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. KPCo is considered to have a significant interest in the variability of AEPSC due to its activity in AEPSC's cost reimbursement structure. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. Total billings from AEPSC for the years ended December 31, 2009 and 2008 were $34 million and $46 million, respectively. The carrying amount of liabilities associated with AEPSC for the years ended December 31, 2009 and 2008 were $4 million and $5 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant Unit 1 and leases a 50% interest in Rockport Plant Unit 2. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP guarantees all the debt obligations of AEGCo. KPCo is considered to have a significant interest in AEGCo due to its transactions. KPCo is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. Due to the nature of the AEP Power Pool, there is a sharing of the cost of Rockport Plant such that no member of the AEP Power Pool is the primary beneficiary of AEGCo's Rockport Plant. In the event AEGCo would require financing or other support outside the billings to KPCo, this financing would be provided by AEP. Total billings from AEGCo for the years ended December 31, 2009 and 2008 were $102 million and $106 million, respectively. The carrying amount of liabilities associated with AEGCo for the years ended December 31, 2009 and 2008 were both $9 million. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

13. PROPERTY, PLANT AND EQUIPMENT

Depreciation

KPCo provides for depreciation of Property, Plant and Equipment on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following table provides the annual composite depreciation rates by functional class:

2009	Regulated					Nonregulated				
Functional Class of Property	Property, Plant and Equipment (in thousands)	Accumulated Depreciation (in thousands)	Annual Composite Depreciation Rate	Depreciable Life Ranges (in years)		Property, Plant and Equipment (in thousands)	Accumulated Depreciation (in thousands)	Annual Composite Depreciation Rate	Depreciable Life Ranges (in years)	
Production	$ 547,378	$ 190,020	3.8%	40-50		$ -	$ -	-	-	
Transmission	438,775	142,966	1.7%	25-75		-	-	-	-	
Distribution	569,389	156,181	3.4%	11-75		-	-	-	-	
CWIP	28,409	(3,767)	N.M.	N.M.		-	-	-	-	
Other	53,504	23,218	9.7%	N.M.		5,498	188	N.M.	N.M.	
Total	$ 1,637,455	$ 508,618				$ 5,498	$ 188			

2008	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment (in thousands)	Accumulated Depreciation (in thousands)	Annual Composite Depreciation Rate	Depreciable Life Ranges (in years)	Property, Plant and Equipment (in thousands)	Accumulated Depreciation (in thousands)	Annual Composite Depreciation Rate	Depreciable Life Ranges (in years)
Production	$ 533,998	$ 177,679	3.5%	40-50	$ -	$ -	-	-
Transmission	431,835	135,955	1.6%	25-75	-	-	-	-
Distribution	528,711	146,009	3.4%	11-75	-	-	-	-
CWIP	46,650	(7,936)	N.M.	N.M.	-	-	-	-
Other	59,994	24,684	8.1%	N.M.	5,491	177	N.M.	N.M.
Total	$ 1,601,188	$ 476,391			$ 5,491	$ 177		

2007	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges (in years)	Annual Composite Depreciation Rate	Depreciable Life Ranges (in years)
Production	3.8%	40-50	-	-
Transmission	1.7%	25-75	-	-
Distribution	3.4%	11-75	-	-
CWIP	N.M.	N.M.	-	-
Other	8.7%	N.M.	N.M.	N.M.

N.M. = Not Meaningful

The composite depreciation rate generally includes a component for nonasset retirement obligation (non-ARO) removal costs, which is credited to Accumulated Depreciation and Amortization. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability.

Asset Retirement Obligations (ARO)

KPCo records ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for the retirement of asbestos removal. KPCo has identified, but not recognized, ARO liabilities related to electric transmission and distribution assets, as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since KPCo plans to use its facilities indefinitely. The retirement obligation would only be recognized if and when KPCo abandons or ceases the use of specific easements, which is not expected.

The following is a reconciliation of the 2009 and 2008 aggregate carrying amounts of ARO for KPCo:

Year	ARO at January 1,	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO at December 31,
			(in thousands)			
2009	$ 3,275	$ 297	$ -	$ (66)	$ -	$ 3,506
2008	944	52	-	(590)	2,869	3,275

Allowance for Funds Used During Construction (AFUDC)

KPCo's amounts of allowance for borrowed and equity funds used during construction are summarized in the following table:

	Years Ended December 31, 2009	2008	2007
		(in thousands)	
Allowance for Equity Funds Used During Construction	$ 391	$ 1,012	$ 260
Allowance for Borrowed Funds Used During Construction	394	1,701	595

14. UNAUDITED QUARTERLY FINANCIAL INFORMATION

In management's opinion, the unaudited quarterly information reflects all normal and recurring accruals and adjustments necessary for a fair presentation of the results of operations for interim periods. Quarterly results are not necessarily indicative of a full year's operations because of various factors. KPCo's unaudited quarterly financial information is as follows:

	2009 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
		(in thousands)		
Revenues	$ 178,433	$ 155,099	$ 152,153	$ 146,841
Operating Income	20,053	18,144	10,923	17,669
Net Income	9,454	6,208	1,309	6,965

	2008 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
		(in thousands)		
Revenues	$ 167,290	$ 147,051	$ 188,872	$ 162,347 (a)
Operating Income	21,557	21,528	16,770	3,992 (a)
Net Income (Loss)	11,144	10,930	7,451	(4,994)(a)

(a) See "Allocation of Off-system Sales Margins" section of Note 2 for discussion of the financial statement impact of the FERC's November 2008 order related to the SIA.

There were no significant events in 2009.