Kentucky Power Company

2010 Annual Report

Financial Statements

AEP AMERICAN® ELECTRIC POWER

TABLE OF CONTENTS

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.
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.
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.
NO_x	Nitrogen oxide.
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.

Term	Meaning
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.
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.
VIE	Variable Interest Entity.
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, 2010 and 2009, 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, 2010. 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, 2010 and 2009, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 25, 2011

KENTUCKY POWER COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2010, 2009 and 2008
(in thousands)

	2010	2009	2008
REVENUES			
Electric Generation, Transmission and Distribution	$ 623,100	$ 567,564	$ 597,699
Sales to AEP Affiliates	60,005	62,613	66,249
Other Revenues	567	2,349	1,612
TOTAL REVENUES	683,672	632,526	665,560
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	185,938	188,525	171,215
Purchased Electricity for Resale	21,422	24,839	26,157
Purchased Electricity from AEP Affiliates	208,400	198,320	234,379
Other Operation	68,972	51,417	64,330
Maintenance	46,223	38,888	47,921
Depreciation and Amortization	52,867	52,010	48,067
Taxes Other Than Income Taxes	10,995	11,738	9,644
TOTAL EXPENSES	594,817	565,737	601,713
OPERATING INCOME	88,855	66,789	63,847
Other Income (Expense):			
Interest Income	239	218	2,103
Allowance for Equity Funds Used During Construction	768	391	1,012
Interest Expense	(36,442)	(33,812)	(34,535)
INCOME BEFORE INCOME TAX EXPENSE	53,420	33,586	32,427
Income Tax Expense	18,138	9,650	7,896
NET INCOME	$ 35,282	$ 23,936	$ 24,531

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, 2010, 2009 and 2008
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
Common Stock Dividends			(21,000)		(21,000)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					410,784
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $81				150	150
NET INCOME			35,282		35,282
TOTAL COMPREHENSIVE INCOME					35,432
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2010	$ 50,450	$ 238,750	$ 157,467	$ (451)	$ 446,216

See Notes to Financial Statements.

KENTUCKY POWER COMPANY
BALANCE SHEETS
ASSETS
December 31, 2010 and 2009
(in thousands)

	2010	2009
CURRENT ASSETS		
Cash and Cash Equivalents	$ 281	$ 494
Advances to Affiliates	67,060	-
Accounts Receivable:		
Customers	21,652	17,593
Affiliated Companies	17,616	8,692
Accrued Unbilled Revenues	3,823	4,806
Miscellaneous	587	1,304
Allowance for Uncollectible Accounts	(623)	(851)
Total Accounts Receivable	43,055	31,544
Fuel	16,640	36,168
Materials and Supplies	24,378	18,248
Risk Management Assets	8,697	13,687
Accrued Tax Benefits	1,420	29,540
Margin Deposits	5,357	5,925
Prepayments and Other Current Assets	1,497	2,416
TOTAL CURRENT ASSETS	168,385	138,022
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	553,589	547,378
Transmission	444,303	438,775
Distribution	590,606	569,389
Other Property, Plant and Equipment	63,982	59,002
Construction Work in Progress	34,093	28,409
Total Property, Plant and Equipment	1,686,573	1,642,953
Accumulated Depreciation and Amortization	542,443	508,806
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,144,130	1,134,147
OTHER NONCURRENT ASSETS		
Regulatory Assets	213,593	206,074
Long-term Risk Management Assets	8,030	9,498
Deferred Charges and Other Noncurrent Assets	37,946	40,178
TOTAL OTHER NONCURRENT ASSETS	259,569	255,750
TOTAL ASSETS	$ 1,572,084	$ 1,527,919

See Notes to Financial Statements.

KENTUCKY POWER COMPANY
BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
December 31, 2010 and 2009

	2010	2009
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ -	$ 485
Accounts Payable:		
General	33,334	42,595
Affiliated Companies	45,790	27,341
Risk Management Liabilities	5,959	5,190
Customer Deposits	19,692	18,258
Accrued Taxes	23,741	12,625
Accrued Interest	7,570	7,466
Other Current Liabilities	26,227	26,996
TOTAL CURRENT LIABILITIES	162,313	140,956
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	528,888	528,722
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	2,303	4,101
Deferred Income Taxes	316,389	304,549
Regulatory Liabilities and Deferred Investment Tax Credits	34,991	35,678
Employee Benefits and Pension Obligations	49,298	49,843
Deferred Credits and Other Noncurrent Liabilities	11,686	12,286
TOTAL NONCURRENT LIABILITIES	963,555	955,179
TOTAL LIABILITIES	1,125,868	1,096,135
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	238,750
Retained Earnings	157,467	143,185
Accumulated Other Comprehensive Income (Loss)	(451)	(601)
TOTAL COMMON SHAREHOLDER'S EQUITY	446,216	431,784
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 1,572,084	$ 1,527,919

See Notes to Financial Statements.

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2010, 2009 and 2008
(in thousands)

	2010	2009	2008
OPERATING ACTIVITIES			
Net Income	$ 35,282	$ 23,936	$ 24,531
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	52,867	52,010	48,067
Deferred Income Taxes	1,075	50,612	4,097
Deferral of Storm Costs	-	(24,355)	-
Allowance for Equity Funds Used During Construction	(768)	(391)	(1,012)
Mark-to-Market of Risk Management Contracts	5,651	(2,386)	(4,650)
Pension Contributions to Qualified Plan Trust	(6,184)	-	-
Fuel Over/Under-Recovery, Net	(923)	11,740	(5,528)
Change in Other Noncurrent Assets	7,084	1,452	(11,298)
Change in Other Noncurrent Liabilities	(4,619)	(2,943)	2,055
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(12,035)	(444)	8,317
Fuel, Materials and Supplies	14,512	(13,643)	(18,866)
Accounts Payable	11,228	(7,149)	21,288
Accrued Taxes, Net	37,721	(29,470)	(4,199)
Other Current Assets	1,514	(1,177)	(3,953)
Other Current Liabilities	1,198	(2,997)	2,473
Net Cash Flows from Operating Activities	143,603	54,795	61,322
INVESTING ACTIVITIES			
Construction Expenditures	(54,058)	(63,963)	(129,619)
Change in Advances to Affiliates, Net	(67,060)	-	-
Acquisitions of Assets	(254)	(316)	(314)
Proceeds from Sales of Assets	700	927	947
Net Cash Flows Used for Investing Activities	(120,672)	(63,352)	(128,986)
FINANCING ACTIVITIES			
Capital Contribution from Parent	-	30,000	-
Issuance of Long-term Debt – Nonaffiliated	-	129,292	-
Change in Advances from Affiliates, Net	(485)	(130,914)	112,246
Retirement of Long-term Debt – Nonaffiliated	-	-	(30,000)
Principal Payments for Capital Lease Obligations	(1,674)	(749)	(806)
Dividends Paid on Common Stock	(21,000)	(19,500)	(14,000)
Other Financing Activities	15	276	143
Net Cash Flows from (Used for) Financing Activities	(23,144)	8,405	67,583
Net Decrease in Cash and Cash Equivalents	(213)	(152)	(81)
Cash and Cash Equivalents at Beginning of Period	494	646	727
Cash and Cash Equivalents at End of Period	$ 281	$ 494	$ 646
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 35,838	$ 37,402	$ 28,602
Net Cash Paid (Received) for Income Taxes	(16,700)	(8,713)	3,554
Noncash Acquisitions Under Capital Leases	4,202	829	544
Construction Expenditures Included in Accounts Payable at December 31,	3,411	5,451	9,662
SIA Refund Included in Accounts Payable at December 31,	-	-	18,526

See Notes to Financial Statements.

INDEX OF 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 174,000 retail customers in its service territory in eastern Kentucky. KPCo also sells power at wholesale to municipalities.

Originally approved by the FERC in 1951 and subsequently amended in 1951, 1962, 1975, 1979 (twice) and 1980, the Interconnection Agreement establishes the AEP Power Pool which permits the AEP East companies to pool their generation assets on a cost basis. It establishes an allocation method for generating capacity among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. AEP Power Pool members are compensated for their costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold and relative peak demand changes. 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 MLR, which determines each member's percentage share of revenues and costs.

In December 2010, each member gave notice to AEPSC and the other AEP Power Pool members of its decision to terminate the Interconnection Agreement effective January 1, 2014 or such other date approved by the FERC, subject to state regulatory input. It is unknown at this time whether the AEP Power Pool will be replaced by a new agreement among some or all of the members, whether individual companies will enter into bilateral or multi-party contracts with each other for power sales and purchases or asset transfers or if each company will choose to operate independently. This decision to terminate is subject to management's ongoing evaluation. The AEP Power Pool members may revoke their notices of termination. If KPCo experiences decreases in revenues or increases in costs as a result of the termination of the AEP Power Pool and is unable to recover the change in revenues and costs through rates, prices or additional sales, it would have an adverse impact on future net income and cash flows.

The AEP East companies are parties to a Transmission Agreement defining how they share the costs associated with their relative ownership of transmission assets. This sharing was based upon each company's MLR until the FERC approved a new Transmission Agreement effective November 1, 2010. The impacts of the new Transmission Agreement will be phased-in for retail rates, adds KGPCo and WPCo as parties to the agreement and changes the allocation method.

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. AEPSC 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 KPSC also regulates certain intercompany transactions under its affiliate statutes. Both the FERC and state regulatory commissions are permitted to review and audit the relevant books and records of companies within a public utility holding company system.

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 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.

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, storm costs, 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 on a daily basis, excluding receivables from risk management activities, for KPCo. See "Sale of Receivables – AEP Credit" section of Note 11 for additional information.

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense related to receivables purchased from KPCo. For customer accounts receivables relating to risk management activities, accounts receivables are reviewed for bad debt reserves at a specific counterparty level basis. For miscellaneous accounts receivable, bad debt expense is recorded for all amounts outstanding 180 days or greater at 100%, unless specifically identified. Miscellaneous accounts receivable items open less than 180 days may be reserved using specific identification for bad debt reserves.

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, 2010.

Management monitors credit levels and the financial condition of KPCo's 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 Deferred Charges and Other Noncurrent Assets. 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 Prepayments and Other Current Assets. 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 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 or investment is the amount at which that asset or 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. KPCo records the equity component of AFUDC in Allowance for Equity Funds Used During Construction and the debt component of AFUDC as a reduction to Interest Expense.

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 such as commodity, interest rate and, to a lesser degree, volatility or credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

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

AEP utilizes its trustee's external pricing service 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.

Assets in the benefits trust are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equity securities. They are valued based on observable inputs primarily unadjusted quoted prices in active markets for identical assets. 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.

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

	Type of Fixed Income Security		
Type of Input	**United States Government**	**Corporate Debt**	**State and Local Government**
Benchmark Yields	X	X	X
Broker Quotes	X	X	X
Discount Margins	X	X	
Treasury Market Update	X		
Base Spread	X	X	X
Corporate Actions		X	
Ratings Agency Updates		X	X
Prepayment Schedule and History			X
Yield Adjustments	X		

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, purchases of power in excess of sales to PJM, on an hourly net basis, used to serve retail load are 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 arising from non-derivative contracts are accounted for on a gross basis in Purchased Electricity for Resale on the Statements of Income. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's economic substance. Purchases under non-trading derivatives used to serve accrual based obligations are recorded in Purchased Electricity for Resale on the Statements of Income. All other non-trading derivative purchases are recorded net in revenues.

In general, 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, as well as 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 recognize 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 %	32.0 %	37.0 %
Cash	1.0 %	2.0 %	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 Voluntary Employees' Beneficiary Association (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. KPCo's components of AOCI as of December 31, 2010 and 2009 are shown in the following table:

	December 31,	
Components	**2010**	**2009**
	(in thousands)	
Cash Flow Hedges, Net of Tax	$ (451)	$ (601)

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 25, 2011, the date that KPCo's 2010 annual report was issued.

Adjustments to Sale of Receivables Disclosure

In the "Sale of Receivables – AEP Credit" section of Note 11, the disclosure was expanded for KPCo to reflect certain prior period amounts related to the sale of receivables that were not previously disclosed. These omissions were not material to the disclosure and had no impact on KPCo's previously reported net income, changes in shareholder's equity, financial position or cash flows.

Adjustments to Benefit Plans Footnote

In Note 5 – Benefit Plans, the disclosure was expanded to reflect disclosure requirements based upon KPCo's participation in the AEP System. These omissions were not material to the financial statements and had no impact on KPCo's previously reported net income, changes in shareholder's equity, financial position or cash flows.

2. RATE MATTERS

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

Kentucky Base Rate Filing

In December 2009, KPCo filed a base rate case with the KPSC to increase base revenues by $124 million annually based on an 11.75% return on common equity. The base rate case also requested recovery of deferred storm restoration expenses over a three-year period. In June 2010, the KPSC approved a settlement agreement to increase base revenues by $64 million annually based on a 10.5% return on common equity. The settlement agreement included recovery of $23 million of deferred storm restoration expenses over five years. New rates became effective with the first billing cycle of July 2010.

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. 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. The KPSC filed for a discretionary review of the related Duke Energy case with the Kentucky Supreme Court. In October 2010, the Kentucky Supreme Court ruled that as long as rates established by a utility are fair, just and reasonable, the KPSC has broad ratemaking power to allow recovery of costs outside of a general rate case, even without a statute specifically authorizing recovery of such costs.

FERC Rate Matters

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. 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 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 asking the FERC to reverse the decision. In May 2010, the FERC issued an order that generally supports AEP's position and requires a compliance filing to be filed with the FERC by August 2010. In June 2010, AEP and other affected companies filed a joint request for rehearing with the FERC.

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 a reserve of $3.3 million.

Settlements approved by the FERC consumed $10 million of the reserve for refunds applicable to $112 million of SECA revenue. In December 2010, the FERC issued an order approving a settlement agreement resulting in the collection of $2 million of previously deemed uncollectible SECA revenue. Therefore, the AEP East companies reduced their reserves for net refunds for SECA settlements by $2 million. The balance in the reserve for future settlements as of December 31, 2010 was $32 million. KPCo's portion of the reserve balance at December 31, 2010 was $2.4 million.

In August 2010, the affected companies, including the AEP East companies, filed a compliance filing with the FERC. If the compliance filing is accepted, the AEP East companies would have to pay refunds of approximately $20 million including estimated interest of $5 million. The AEP East companies could also potentially receive payments up to approximately $10 million including estimated interest of $3 million. KPCo's portion of the potential refund payments and potential payments to be received are $1.5 million and $800 thousand, respectively. A decision is pending from the FERC.

Based on the AEP East companies' analysis of the May 2010 order and the compliance filing, management believes that the reserve is adequate to pay the refunds, including interest, that will be required should the May 2010 order or the compliance filing be made final. Management cannot predict the ultimate outcome of this proceeding at the FERC which could impact future net income and cash flows.

Modification of the Transmission Agreement (TA)

The AEP East companies are parties to the TA that provides for a sharing of the cost of transmission lines operated at 138-kV and above and transmission stations containing extra-high voltage facilities. In June 2009, AEPSC, on behalf of the parties to the TA, filed with the FERC a request to modify the TA. Under the proposed amendments, KGPCo and WPCo will be added as parties to the TA. In addition, the amendments would provide for the allocation of PJM transmission costs generally 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. In October 2010, the FERC approved a settlement agreement for the new TA effective November 1, 2010. The impacts of the settlement agreement will be phased-in for retail rate making purposes in certain jurisdictions over periods of up to four years.

PJM Transmission Formula Rate Filing

AEP filed an application with the FERC in July 2008 to increase its open access transmission tariff (OATT) rates for wholesale transmission service within PJM. The filing sought to implement a formula rate allowing annual adjustments reflecting future changes in the AEP East companies' cost of service. The FERC issued an order conditionally accepting AEP's proposed formula rate and delayed the requested October 2008 effective date for five months. AEP began settlement discussions with the intervenors and the FERC staff which resulted in a settlement that was filed with the FERC in April 2010.

In October 2010, a settlement agreement was approved by the FERC which resulted in a $51 million annual increase beginning in April 2009 for service as of March 2009, of which approximately $7 million is being collected from nonaffiliated customers within PJM. Prior to November 2010, the remaining $44 million was billed to the AEP East companies and was generally offset by compensation from PJM for use of the AEP East companies' transmission facilities so that net income was not directly affected. Beginning in November 2010, AEP East companies, KGPCo and WPCo, which are parties to the modified TA, allocate revenue and expenses on different methodologies and will affect net income. See "Modification of the Transmission Agreement" above.

The settlement also results in an additional $30 million increase for the first annual update of the formula rate, beginning in August 2009 for service as of July 2009. Approximately $4 million of the increase will be collected from nonaffiliated customers within PJM with the remaining $26 million being billed to the AEP East companies.

Under the formula, an annual update will be filed to be effective July 2010 and each year thereafter. Also, beginning with the July 2010 update, the rates each year will include an adjustment to true-up the prior year's collections to the actual costs for the prior year. In May 2010, the second annual update was filed with the FERC to decrease the revenue requirement by $58 million for service as of July 2010. Approximately $8 million of the decrease will be refunded to nonaffiliated customers within PJM.

PJM/MISO Market Flow Calculation Settlement Adjustments

During 2009, an analysis conducted by MISO and PJM discovered several instances of unaccounted for power flows on numerous coordinated flowgates. These flows affected the settlement data for congestion revenues and expenses and dated back to the start of the MISO market in 2005. In January 2011, PJM and MISO reached a settlement agreement where the parties agreed to net various issues to zero. This settlement was filed with the FERC in January 2011. PJM and MISO are currently awaiting final approval from the FERC.

Transmission Agreement (TA)

Certain transmission facilities placed in service in 1998 were inadvertently excluded from the AEP East companies' TA calculation prior to January 2009. The excluded equipment was KPCo's Inez Station which had been determined as eligible equipment for inclusion in the TA in 1995 by the AEP TA transmission committee. The amount involved was $7 million annually. In June 2010, the KPSC approved a settlement agreement in KPCo's base rate filing which set new base rates effective July 2010 and excluded consideration of this issue.

3. EFFECTS OF REGULATION

Regulatory assets and liabilities are comprised of the following items:

Regulatory Assets:	**December 31, 2010**	**2009**	**Remaining Recovery Period**
	(in thousands)		
Noncurrent Regulatory Assets			
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:			
Regulatory Assets Currently Not Earning a Return			
Storm Related Costs	$ - (a)	$ 24,355	
Total Regulatory Assets Not Yet Being Recovered	-	24,355	
Regulatory assets being recovered:			
Regulatory Assets Currently Earning a Return			
RTO Formation/Integration Costs	1,373	1,538	9 years
Unamortized Loss on Reacquired Debt	737	771	22 years
Regulatory Assets Currently Not Earning a Return			
Income Taxes, Net	123,789	114,131	23 years
Pension and OPEB Funded Status	58,853	56,848	13 years
Storm Related Costs	21,143 (a)	-	5 years
Postemployment Benefits	6,456	7,077	4 years
Other Regulatory Assets Being Recovered	1,242	1,354	various
Total Regulatory Assets Being Recovered	213,593	181,719	
Total Noncurrent Regulatory Assets	$ 213,593	$ 206,074	

Regulatory Liabilities:	**December 31, 2010**	**2009**	**Remaining Refund Period**
	(in thousands)		
Current Regulatory Liability			
Over-recovered Fuel Costs - does not pay a return	$ 864	$ 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	27,975	24,979	(b)
Regulatory Liabilities Currently Not Paying a Return			
Unrealized Gain on Forward Commitments	5,844	8,977	5 years
Deferred Investment Tax Credits	993	1,697	10 years
Other Regulatory Liabilities Being Paid	179	25	various
Total Regulatory Liabilities Being Paid	34,991	35,678	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 34,991	$ 35,678	

(a) Recovery of regulatory asset was granted during 2010.
(b) 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. Management forecasts approximately $86 million of construction expenditures excluding AFUDC for 2011. 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, 2010:

Contractual Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 181.9	$ 188.7	$ -	$ -	$ 370.6
Energy and Capacity Purchase Contracts (b)	0.9	0.4	0.1	-	1.4
Total	$ 182.8	$ 189.1	$ 0.1	$ -	$ 372.0

(a) Represents contractual commitments to purchase coal 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.

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. 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.

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 Clean Air Act 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 December 2010, the defendants' petition for review by the U.S. Supreme Court was granted. Briefing is underway and the case will be heard in April 2011. Management believes the actions are without merit and intends to continue to defend against the claims.

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. The court granted petitions for rehearing. An additional recusal left the Fifth Circuit without a quorum to reconsider the decision and the appeal was dismissed, leaving the district court's decision in place. Plaintiffs filed a petition with the U.S. Supreme Court asking the court to remand the case to the Fifth Circuit and reinstate the panel decision. The petition was denied in January 2011.

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

Alaskan Villages' Claims

In 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil and gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of 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. Briefing is complete and no date has been set for oral argument. The defendants requested that the court defer setting this case for oral argument until after the Supreme Court issues its decision in the CO_2 public nuisance case discussed above. Management believes the action is without merit and intends to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

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

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 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, 2010, there is one site for which KPCo has received an information request which could lead 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 suspended. 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 were fundamental design deficiencies and that inferior and/or inappropriate materials were selected for the internal fiberglass components. Management initiated discussions with Black & Veatch, the original equipment manufacturer, to develop a repair or replacement corrective action plan. In 2010, management settled with Black & Veatch and resolved the issues involving the internal components and JBR vessel corrosion. These settlements resulted in an immaterial increase in the capitalized costs of the projects for modification of the scope of the contracts.

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 which covers substantially all of KPCo's employees. KPCo also participates in OPEB plans sponsored by AEP to provide medical and life insurance benefits for retired employees.

KPCo recognizes its funded status associated with defined benefit pension and OPEB plans in its balance sheets. Disclosures about the plans are required by the "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 instead of other comprehensive income for qualifying benefit costs of regulated operations that for ratemaking purposes are deferred for future recovery. The cumulative funded status adjustment is 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 a regulatory asset and deferred gains result in a regulatory liability.

Actuarial Assumptions for Benefit Obligations

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

	Pension Plans		Other Postretirement Benefit Plans	
Assumptions	**2010**	**2009**	**2010**	**2009**
Discount Rate	5.05 %	5.60 %	5.25 %	5.85 %
Rate of Compensation Increase	4.55 % (a)	4.20 % (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

A duration-based method is used to determine the discount rate for the plans. A hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's Aa bond index is constructed 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 2010, the rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 11.5% per year, with an average increase of 4.55%.

Actuarial Assumptions for Net Periodic Benefit Costs

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

	Pension Plans			Other Postretirement Benefit Plans		
	2010	**2009**	**2008**	**2010**	**2009**	**2008**
Discount Rate	5.60 %	6.00 %	6.00 %	5.85 %	6.10 %	6.20 %
Expected Return on Plan Assets	8.00 %	8.00 %	8.00 %	8.00 %	7.75 %	8.00 %
Rate of Compensation Increase	4.20 %	5.50 %	5.50 %	N/A	N/A	N/A

N/A Not Applicable

The expected return on plan assets for 2010 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	2010	2009
Initial	8.00 %	6.50 %
Ultimate	5.00 %	5.00 %
Year Ultimate Reached	2016	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 thousands)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 557	$ (449)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	6,689	(5,488)

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 credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. The plans are monitored to control security diversification and ensure compliance with the investment policy. At December 31, 2010, 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.

Benefit Plan Obligations, Plan Assets and Funded Status as of December 31, 2010 and 2009

The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets and funded status as of December 31. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

	Pension Plans		**Other Postretirement Benefit Plans**	
	2010	**2009**	**2010**	**2009**
Change in Benefit Obligation	**(in thousands)**			
Benefit Obligation at January 1	$ 108,511	$ 98,421	$ 50,826	$ 48,580
Service Cost	2,549	2,572	1,060	971
Interest Cost	5,900	5,861	2,953	2,866
Actuarial Loss	7,073	7,159	4,964	213
Plan Amendment Prior Service Credit	-	-	(679)	-
Benefit Payments	(10,441)	(5,502)	(3,163)	(2,525)
Participant Contributions	-	-	649	526
Medicare Subsidy	-	-	196	195
Benefit Obligation at December 31	$ 113,592	$ 108,511	$ 56,806	$ 50,826
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 81,637	$ 74,612	$ 35,553	$ 27,868
Actual Gain on Plan Assets	11,286	12,527	5,134	6,224
Company Contributions	6,184	-	2,593	3,460
Participant Contributions	-	-	649	526
Benefit Payments	(10,441)	(5,502)	(3,163)	(2,525)
Fair Value of Plan Assets at December 31	$ 88,666	$ 81,637	$ 40,766	$ 35,553
Underfunded Status at December 31	$ (24,926)	$ (26,874)	$ (16,040)	$ (15,273)

Amounts Recognized on the Balance Sheets as of December 31, 2010 and 2009

	Pension Plans		**Other Postretirement Benefit Plans**	
	December 31,			
	2010	**2009**	**2010**	**2009**
	(in thousands)			
Employee Benefits and Pension Obligations - Accrued Long-term Benefit Liability	$ (24,926)	$ (26,874)	$ (16,040)	$ (15,273)
Underfunded Status	$ (24,926)	$ (26,874)	$ (16,040)	$ (15,273)

Amounts Included in Regulatory Assets as of December 31, 2010 and 2009

	Pension Plans		**Other Postretirement Benefit Plans**	
	December 31,			
	2010	**2009**	**2010**	**2009**
Components	**(in thousands)**			
Net Actuarial Loss	$ 42,392	$ 41,003	$ 16,453	$ 14,519
Prior Service Cost (Credit)	429	579	(421)	-
Transition Obligation	-	-	-	747
Recorded as				
Regulatory Assets	$ 42,821	$ 41,582	$ 16,032	$ 15,266

Components of the change in amounts included in Regulatory Assets during the years ended December 31, 2010 and 2009 are as follows:

Components	Pension Plans 2010	Pension Plans 2009	Other Postretirement Benefit Plans 2010	Other Postretirement Benefit Plans 2009
	Years Ended December 31, (in thousands)			
Actuarial Loss (Gain) During the Year	$ 3,441	$ 2,316	$ 2,665	$ (3,856)
Prior Service Credit	-	-	(679)	-
Amortization of Actuarial Loss	(2,052)	(1,318)	(732)	(1,094)
Amortization of Prior Service Cost	(150)	(151)	-	-
Amortization of Transition Obligation	-	-	(488)	(488)
Change for the Year	$ 1,239	$ 847	$ 766	$ (5,438)

Pension and Other Postretirement Plans' Assets

The following table presents the classification of pension plan assets within the fair value hierarchy at December 31, 2010:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 31,021	$ 63	$ -	$ -	$ 31,084	35.1 %
International	9,259	-	-	-	9,259	10.4 %
Real Estate Investment Trusts	2,582	-	-	-	2,582	2.9 %
Common Collective Trust - International	-	3,738	-	-	3,738	4.2 %
Subtotal - Equities	42,862	3,801	-	-	46,663	52.6 %
Fixed Income:						
United States Government and Agency Securities	-	14,571	-	-	14,571	16.4 %
Corporate Debt	-	15,439	-	-	15,439	17.4 %
Foreign Debt	-	2,922	-	-	2,922	3.3 %
State and Local Government	-	522	-	-	522	0.6 %
Other - Asset Backed	-	1,175	-	-	1,175	1.3 %
Subtotal - Fixed Income	-	34,629	-	-	34,629	39.0 %
Real Estate	-	-	1,912	-	1,912	2.2 %
Alternative Investments	-	-	2,988	-	2,988	3.4 %
Securities Lending	-	5,845	-	-	5,845	6.6 %
Securities Lending Collateral (a)	-	-	-	(6,339)	(6,339)	(7.1)%
Cash and Cash Equivalents (b)	-	2,917	-	37	2,954	3.3 %
Other - Pending Transactions and Accrued Income (c)	-	-	-	14	14	- %
Total	$ 42,862	$ 47,192	$ 4,900	$ (6,288)	$ 88,666	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay cash collateral received as part of the Securities 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 thousands)	
Balance as of January 1, 2010	$ 2,171	$ 2,535	$ 4,706
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	(259)	74	(185)
Relating to Assets Sold During the Period	-	24	24
Purchases and Sales	-	355	355
Transfers into Level 3	-	-	-
Transfers out of Level 3	-	-	-
Balance as of December 31, 2010	$ 1,912	$ 2,988	$ 4,900

The following table presents the classification of OPEB plan assets within the fair value hierarchy at December 31, 2010:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 16,300	$ -	$ -	$ -	$ 16,300	40.0 %
International	6,153	-	-	-	6,153	15.1 %
Common Collective Trust - Global	-	3,203	-	-	3,203	7.9 %
Subtotal - Equities	22,453	3,203	-	-	25,656	63.0 %
Fixed Income:						
Common Collective Trust - Debt	-	1,332	-	-	1,332	3.3 %
United States Government and Agency Securities	-	2,615	-	-	2,615	6.4 %
Corporate Debt	-	3,071	-	-	3,071	7.5 %
Foreign Debt	-	692	-	-	692	1.7 %
State and Local Government	-	98	-	-	98	0.2 %
Other - Asset Backed	-	26	-	-	26	0.1 %
Subtotal - Fixed Income	-	7,834	-	-	7,834	19.2 %
Trust Owned Life Insurance:						
International Equities	-	1,369	-	-	1,369	3.3 %
United States Bonds	-	4,537	-	-	4,537	11.1 %
Cash and Cash Equivalents (a)	572	699	-	24	1,295	3.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	75	75	0.2 %
Total	$ 23,025	$ 17,642	$ -	$ 99	$ 40,766	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 following table presents the classification of pension plan assets within the fair value hierarchy at December 31, 2009:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 29,256	$ -	$ -	$ -	$ 29,256	35.8 %
International	7,674	-	-	-	7,674	9.4 %
Real Estate Investment Trusts	2,080	-	-	-	2,080	2.6 %
Common Collective Trust - International	-	3,864	-	-	3,864	4.7 %
Subtotal - Equities	39,010	3,864	-	-	42,874	52.5 %
Fixed Income:						
United States Government and Agency Securities	-	5,585	-	-	5,585	6.9 %
Corporate Debt	-	19,930	-	-	19,930	24.4 %
Foreign Debt	-	4,100	-	-	4,100	5.0 %
State and Local Government	-	826	-	-	826	1.0 %
Other - Asset Backed	-	657	-	-	657	0.8 %
Subtotal - Fixed Income	-	31,098	-	-	31,098	38.1 %
Real Estate	-	-	2,171	-	2,171	2.7 %
Alternative Investments	-	-	2,535	-	2,535	3.1 %
Securities Lending	-	4,159	-	-	4,159	5.1 %
Securities Lending Collateral (a)	-	-	-	(4,697)	(4,697)	(5.8)%
Cash and Cash Equivalents (b)	-	2,773	-	97	2,870	3.5 %
Other - Pending Transactions and Accrued Income (c)	-	-	-	627	627	0.8 %
Total	$ 39,010	$ 41,894	$ 4,706	$ (3,973)	$ 81,637	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay cash collateral received as part of the Securities 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 thousands)	
Balance as of January 1, 2009	$ 3,295	$ 2,554	$ 5,849
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	(1,124)	(332)	(1,456)
Relating to Assets Sold During the Period	-	10	10
Purchases and Sales	-	303	303
Transfers in and/or out of Level 3	-	-	-
Balance as of December 31, 2009	$ 2,171	$ 2,535	$ 4,706

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

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 9,340	$ -	$ -	$ -	$ 9,340	26.2 %
International	10,190	-	-	-	10,190	28.7 %
Common Collective Trust - Global	-	2,532	-	-	2,532	7.1 %
Subtotal - Equities	19,530	2,532	-	-	22,062	62.0 %
Fixed Income:						
Common Collective Trust - Debt	-	1,032	-	-	1,032	2.9 %
United States Government and Agency Securities	-	1,139	-	-	1,139	3.2 %
Corporate Debt	-	3,847	-	-	3,847	10.8 %
Foreign Debt	-	873	-	-	873	2.4 %
State and Local Government	-	163	-	-	163	0.5 %
Other - Asset Backed	-	38	-	-	38	0.2 %
Subtotal - Fixed Income	-	7,092	-	-	7,092	20.0 %
Trust Owned Life Insurance:						
International Equities	-	2,025	-	-	2,025	5.7 %
United States Bonds	-	3,562	-	-	3,562	10.0 %
Cash and Cash Equivalents (a)	179	391	-	27	597	1.7 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	215	215	0.6 %
Total	$ 19,709	$ 15,602	$ -	$ 242	$ 35,553	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.

Determination of Pension Expense

The determination of pension expense or income is based 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, 2010	2009
	(in thousands)	
Qualified Pension Plan	$ 112,820	$ 107,206
Nonqualified Pension Plan	-	7
Total	$ 112,820	$ 107,213

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, 2010 and 2009 were as follows:

	Underfunded Pension Plans	
	2010	2009
	(in thousands)	
Projected Benefit Obligation	$ 113,592	$ 108,511
Accumulated Benefit Obligation	$ 112,820	$ 107,213
Fair Value of Plan Assets	88,666	81,637
Underfunded Accumulated Benefit Obligation	$ (24,154)	$ (25,576)

Estimated Future Benefit Payments and Contributions

KPCo expects contributions for the pension plan of $2.5 million and the OPEB plans of $2 million during 2011. The estimated contributions to the pension trust are at least the minimum amount required by ERISA and additional discretionary contributions may be made to maintain the funded status of the plan. The contributions to the OPEB plans are generally based on the amount of the OPEB plans' periodic benefit costs for accounting purposes as provided 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 KPCo's assets. The payments include the participants' contributions to the plan for their share of the cost. 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 pension benefits and OPEB are as follows:

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	Benefit Payments	Medicare Subsidy Receipts
		(in thousands)	
2011	$ 6,503	$ 3,230	$ (220)
2012	6,697	3,444	(244)
2013	6,817	3,660	(276)
2014	7,121	3,875	(304)
2015	7,305	4,126	(333)
Years 2016 to 2020, in Total	41,440	24,149	(2,178)

Components of Net Periodic Benefit Cost

The following table provides the components of net periodic benefit cost for the years ended December 31, 2010, 2009 and 2008:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2010	2009	2008	2010	2009	2008
	(in thousands)					
Service Cost	$ 2,549	$ 2,572	$ 2,508	$ 1,060	$ 971	$ 992
Interest Cost	5,900	5,861	5,712	2,953	2,866	2,966
Expected Return on Plan Assets	(7,654)	(7,684)	(7,883)	(2,841)	(2,187)	(3,031)
Amortization of Transition Obligation	-	-	-	488	488	488
Amortization of Prior Service Cost	150	151	153	-	-	-
Amortization of Net Actuarial Loss	2,052	1,318	505	732	1,094	203
Net Periodic Benefit Cost	2,997	2,218	995	2,392	3,232	1,618
Capitalized Portion	(1,064)	(825)	(454)	(849)	(1,202)	(738)
Net Periodic Benefit Cost Recognized as Expense	$ 1,933	$ 1,393	$ 541	$ 1,543	$ 2,030	$ 880

Estimated amounts expected to be amortized to net periodic benefit costs and the impact on the balance sheet during 2011 are shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in thousands)	
Net Actuarial Loss	$ 2,846	$ 858
Prior Service Cost (Credit)	150	(35)
Total Estimated 2011 Amortization	$ 2,996	$ 823
Expected to be Recorded as		
Regulatory Asset	$ 2,996	$ 823
Total	$ 2,996	$ 823

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 matching contributions. The matching contributions to the plan were 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 $1.4 million in 2010, $1.7 million in 2009 and $1.6 million in 2008.

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, credit risk and, to a lesser extent, foreign currency exchange 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

Trading Strategies

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

Risk Management Strategies

The strategy surrounding the use of derivative instruments focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. To accomplish these objectives, AEPSC, on behalf of 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 power, coal, natural gas, interest rate and, to a lesser degree, heating oil and gasoline, emission allowance and other commodity contracts to manage the risk associated with the energy business. AEPSC, on behalf of 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 and foreign currency risk associated with future purchase obligations denominated in foreign currencies. 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, 2010 and 2009:

Notional Volume of Derivative Instruments

	Volume December 31, 2010	Volume December 31, 2009	Unit of Measure
	(in thousands)		
Commodity:			
Power	40,277	38,509	MWHs
Coal	3,280	2,230	Tons
Natural Gas	449	3,600	MMBtus
Heating Oil and Gasoline	274	306	Gallons
Interest Rate	$ 2,008	$ 4,239	USD

Fair Value Hedging Strategies

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

Cash Flow Hedging Strategies

AEPSC, on behalf of KPCo, enters into and designates as cash flow hedges certain derivative transactions for the purchase and sale of power, coal, natural gas and heating oil and gasoline ("Commodity") in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and fuel or energy purchases. 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 heating oil and gasoline derivative contracts in order to mitigate price risk of future fuel purchases. For disclosure purposes, these contracts are included with other hedging activity as "Commodity." KPCo does not hedge all 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. Some interest rate derivative transactions effectively modify exposure to interest rate risk by converting a portion of floating-rate debt to a fixed rate. AEPSC, on behalf of KPCo, also enters into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. The anticipated fixed-rate debt offerings have a high probability of occurrence as the proceeds will be used to fund existing debt maturities and projected capital expenditures. KPCo does not hedge all interest rate exposure.

At times, KPCo is exposed to foreign currency exchange rate risks primarily because some fixed assets are purchased from foreign suppliers. In accordance with AEP's risk management policy, AEPSC, on behalf of KPCo, may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. KPCo does not hedge all foreign currency 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 on the balance sheet at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, 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, 2010 and 2009 balance sheets, KPCo netted $400 thousand and $800 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $3.4 million and $6.4 million, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following tables represent the gross fair value impact of KPCo's derivative activity on the Balance Sheets as of December 31, 2010 and 2009:

Fair Value of Derivative Instruments
December 31, 2010

	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	$ 60,231	$ 418	$ -	$ (51,952)	$ 8,697
Long-term Risk Management Assets	16,978	148	-	(9,096)	8,030
Total Assets	77,209	566	-	(61,048)	16,727
Current Risk Management Liabilities	59,107	490	-	(53,638)	5,959
Long-term Risk Management Liabilities	13,265	146	-	(11,108)	2,303
Total Liabilities	72,372	636	-	(64,746)	8,262
Total MTM Derivative Contract Net Assets (Liabilities)	$ 4,837	$ (70)	$ -	$ 3,698	$ 8,465

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 on 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 years ended December 31, 2010 and 2009:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
Years Ended December 31, 2010 and 2009

Location of Gain (Loss)	**2010**	**2009**
	(in thousands)	
Electric Generation, Transmission and Distribution Revenues	$ 10,188	$ 20,402
Sales to AEP Affiliates	(1,272)	(2,162)
Regulatory Assets (a)	(93)	-
Regulatory Liabilities (a)	(2,170)	(2,719)
Total Gain on Risk Management Contracts	$ 6,653	$ 15,521

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

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for "Derivatives and Hedging." Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the 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, management designates a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on 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 some 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), 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 affects Net Income during the period of change.

KPCo records realized and unrealized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on KPCo's Statements of Income. During 2010, 2009 and 2008, KPCo did not employ any fair value hedging strategies.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), 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 derivative contracts for the purchase and sale of power, coal, natural gas and heating oil and gasoline designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on KPCo's Statements of Income, or in Regulatory Assets or Regulatory Liabilities on KPCo's Balance Sheets, depending on the specific nature of the risk being hedged. During 2010 and 2009, KPCo designated commodity derivatives as cash flow hedges.

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 2010 and 2009, KPCo designated cash flow hedging strategies for forecasted fuel purchases.

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 2010, 2009 and 2008, KPCo did not employ any cash flow hedging strategies for interest rates.

The accumulated gains or losses related to foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on KPCo's Balance Sheets into Depreciation and Amortization expense on the Statements of Income over the depreciable lives of the fixed assets that were designated as the hedged items in qualifying foreign currency hedging relationships. During 2010, 2009 and 2008, KPCo did not employ any foreign currency hedging strategies.

During 2010, 2009 and 2008, 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 years ended December 31, 2010 and 2009. All amounts in the following table are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2010

	Commodity	Interest Rate	Total
		(in thousands)	
Balance in AOCI as of December 31, 2009	$ (138)	$ (463)	$ (601)
Changes in Fair Value Recognized in AOCI	(294)	-	(294)
Amount of (Gain) or Loss Reclassified from AOCI			
to Income Statement/within Balance Sheet:			
Electric Generation, Transmission and Distribution Revenues	44	-	44
Purchased Electricity for Resale	390	-	390
Other Operation Expense	(14)	-	(14)
Maintenance Expense	(17)	-	(17)
Interest Expense	-	60	60
Property, Plant and Equipment	(19)	-	(19)
Balance in AOCI as of December 31, 2010	$ (48)	$ (403)	$ (451)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2009

	Commodity	Interest Rate	Total
		(in thousands)	
Balance in AOCI as of December 31, 2008	$ 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)
Balance in AOCI as of December 31, 2009	$ (138)	$ (463)	$ (601)

During 2008, KPCo reclassified $320 thousand of gains from AOCI to net income.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's Balance Sheets at December 31, 2010 and 2009 were:

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2010

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ 81	$ -	$ 81
Hedging Liabilities (a)	(151)	-	(151)
AOCI Loss Net of Tax	(48)	(403)	(451)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(48)	(60)	(108)

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 Sheets.

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, 2010, 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 41 months.

Credit Risk

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

AEPSC, on behalf of 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 the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, KPCo is obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. Management does not anticipate a downgrade below investment grade. The following table represents: (a) the aggregate fair value of such derivative contracts, (b) the amount of collateral KPCo would have been required to post for all derivative and non-derivative contracts if the credit ratings had declined below investment grade and (c) how much was attributable to RTO and ISO activities as of December 31, 2010 and 2009:

	December 31, 2010	December 31, 2009
	(in thousands)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 1,368	$ 449
Amount of Collateral KPCo Would Have Been Required to Post	2,614	1,699
Amount Attributable to RTO and ISO Activities	2,608	1,601

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 outstanding debt in excess of $50 million. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. Management does not anticipate a non-performance event under these provisions. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted by KPCo and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering KPCo's contractual netting arrangements as of December 31, 2010 and 2009:

	December 31, 2010	December 31, 2009
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 15,930	$ 31,215
Amount of Cash Collateral Posted	1,376	628
Additional Settlement Liability if Cross Default Provision is Triggered	4,926	6,537

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 as of December 31, 2010 and 2009 are summarized in the following table:

	December 31, 2010		December 31, 2009	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 548,888	$ 628,623	$ 548,722	$ 599,909

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 the "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, 2010 and 2009. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2010

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (c)	$ 350	$ 73,753	$ 2,862	$ (61,018)	$ 15,947
Cash Flow Hedges:					
Commodity Hedges (a)	-	549	-	(468)	81
Dedesignated Risk Management Contracts (b)	-	-	-	699	699
Total Risk Management Assets	$ 350	$ 74,302	$ 2,862	$ (60,787)	$ 16,727
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (c)	$ 343	$ 69,996	$ 1,789	$ (64,017)	$ 8,111
Cash Flow Hedges:					
Commodity Hedges (a)	-	619	-	(468)	151
Total Risk Management Liabilities	$ 343	$ 70,615	$ 1,789	$ (64,485)	$ 8,262

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

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a)	$ 472	$ 90,327	$ 2,592	$ (72,387)	$ 21,004
Cash Flow Hedges:					
Commodity 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 Commodity Contracts (a)	$ 533	$ 84,831	$ 693	$ (78,030)	$ 8,027
Cash Flow Hedges:					
Commodity Hedges (a)	-	1,040	-	(326)	714
DETM Assignment (d)	-	-	-	550	550
Total Risk Management Liabilities	$ 533	$ 85,871	$ 693	$ (77,806)	$ 9,291

(a) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(b) Represents contracts that were originally MTM but were subsequently elected as normal under the accounting guidance for "Derivatives and Hedging." At the time of the normal election, the MTM value was frozen and no longer fair valued. This MTM value will be amortized into revenues over the remaining life of the contracts.
(c) Substantially comprised of power contracts.
(d) See "Natural Gas Contracts with DETM" section of Note 12.

There have been no transfers between Level 1 and Level 2 during the year ended December 31, 2010.

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

Year Ended December 31, 2010		**Net Risk Management Assets (Liabilities) (in thousands)**
Balance as of December 31, 2009	$	1,899
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)		361
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)		(1,496)
Transfers into Level 3 (d) (h)		232
Transfers out of Level 3 (e) (h)		(2,283)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)		2,360
Balance as of December 31, 2010	$	1,073

Year Ended December 31, 2009		**Net Risk Management Assets (Liabilities) (in thousands)**
Balance as of December 31, 2008	$	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 (f)		(103)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)		1,690
Balance as of December 31, 2009	$	1,899

Year Ended December 31, 2008		**Net Risk Management Assets (Liabilities) (in thousands)**
Balance as of December 31, 2007	$	(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 (f)		(192)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)		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 management commodity contracts for the reporting period.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Represents existing assets or liabilities that were previously categorized as Level 3.
(f) Represents existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during the period.
(g) Relates to the net gains (losses) of those contracts that are not reflected on KPCo's Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities.
(h) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.

9. INCOME TAXES

The details of income taxes as reported are as follows:

	Years Ended December 31, 2010	2009	2008
		(in thousands)	
Income Tax Expense (Credit):			
Current	$ 17,767	$ (40,140)	$ 4,674
Deferred	1,075	50,612	4,097
Deferred Investment Tax Credits	(704)	(822)	(875)
Total Income Taxes	$ 18,138	$ 9,650	$ 7,896

The following 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.

	Years Ended December 31, 2010	2009	2008
		(in thousands)	
Net Income	$ 35,282	$ 23,936	$ 24,531
Income Taxes	18,138	9,650	7,896
Pretax Income	$ 53,420	$ 33,586	$ 32,427
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 18,697	$ 11,755	$ 11,349
Increase (Decrease) in Income Taxes resulting from the following items:			
Depreciation	1,479	2,256	1,169
AFUDC	(720)	(626)	(872)
Removal Costs	(1,364)	(1,465)	(4,110)
Investment Tax Credits, Net	(704)	(822)	(875)
State and Local Income Taxes	2,069	(2,938)	1,072
Other	(1,319)	1,490	163
Total Income Taxes	$ 18,138	$ 9,650	$ 7,896
Effective Income Tax Rate	34.0 %	28.7 %	24.4 %

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

	December 31, 2010	2009
	(in thousands)	
Deferred Tax Assets	$ 29,149	$ 29,427
Deferred Tax Liabilities	(351,734)	(341,896)
Net Deferred Tax Liabilities	$ (322,585)	$ (312,469)
Property-Related Temporary Differences	$ (239,361)	$ (234,969)
Amounts Due from Customers for Future Federal Income Taxes	(28,545)	(27,057)
Deferred State Income Taxes	(41,855)	(36,564)
Deferred Income Taxes on Other Comprehensive Loss	243	324
Accrued Pensions	9,285	9,994
Regulatory Assets	(23,129)	(22,694)
All Other, Net	777	(1,503)
Net Deferred Tax Liabilities	$ (322,585)	$ (312,469)

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 federal 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 adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and 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. KPCo realized the federal cash flow in 2010 as there was sufficient capacity in prior periods to carry the consolidated federal net operating loss back. Most of KPCo's 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:

	Year Ended December 31,		
	2010	**2009**	**2008**
		(in thousands)	
Interest Expense	$ 439	$ 1,113	$ 303
Interest Income	-	-	1,863
Reversal of Prior Period Interest Expense	320	39	-

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

	December 31,	
	2010	**2009**
	(in thousands)	
Accrual for Receipt of Interest	$ 475	$ 416
Accrual for Payment of Interest and Penalties	566	722

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

	2010	2009	2008
		(in thousands)	
Balance at January 1,	$ 2,553	$ 3,345	$ 2,205
Increase - Tax Positions Taken During a Prior Period	970	2,178	-
Decrease - Tax Positions Taken During a Prior Period	(97)	(2,757)	(113)
Increase - Tax Positions Taken During the Current Year	-	-	1,301
Decrease - Tax Positions Taken During the Current Year	(202)	(141)	(144)
Increase - Settlements with Taxing Authorities	-	-	96
Decrease - Settlements with Taxing Authorities	(513)	-	-
Decrease - Lapse of the Applicable Statute of Limitations	-	(72)	-
Balance at December 31,	$ 2,711	$ 2,553	$ 3,345

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $184 thousand, $528 thousand and $881 thousand for 2010, 2009 and 2008, respectively. 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

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 KPCo's net income or financial condition, but provided a cash flow benefit of approximately $10 million.

The Patient Protection and Affordable Care Act and the related Health Care and Education Reconciliation Act (Health Care Acts) were enacted in March 2010. The Health Care Acts amend tax rules so that the portion of employer health care costs that are reimbursed by the Medicare Part D prescription drug subsidy will no longer be deductible by the employer for federal income tax purposes effective for years beginning after December 31, 2012. Because of the loss of the future tax deduction, a reduction in the deferred tax asset related to the nondeductible OPEB liabilities accrued to date was recorded by KPCo in March 2010. This reduction, which was offset by recording net tax regulatory assets, did not materially affect KPCo's net income, cash flows or financial condition for the year ended December 31, 2010.

The Small Business Jobs Act (the Act) was enacted in September 2010. Included in the Act was a one-year extension of the 50% bonus depreciation provision. The Tax Relief, Unemployment Insurance Reauthorization and the Job Creation Act of 2010 extended the life of research and development, employment and several energy tax credits originally scheduled to expire at the end of 2010. In addition, the Act extended the time for claiming bonus depreciation and increased the deduction to 100% for part of 2010 and 2011. The enacted provisions will not have a material impact on KPCo's net income or financial condition but had a favorable impact on cash flows of approximately $8 million in 2010.

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 resulted in a 2010 cash flow benefit to KPCo of approximately $20 million.

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 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	**2010**	**2009**	**2008**
		(in thousands)	
Net Lease Expense on Operating Leases	$ 836	$ 1,948	$ 2,250
Amortization of Capital Leases	1,673	746	971
Interest on Capital Leases	304	53	102
Total Lease Rental Costs	$ 2,813	$ 2,747	$ 3,323

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,	
	2010	**2009**
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Generation	$ 683	$ 504
Other Property, Plant and Equipment	6,511	2,876
Total Property, Plant and Equipment Under Capital Leases	7,194	3,380
Accumulated Amortization	1,781	1,627
Net Property, Plant and Equipment Under Capital Leases	$ 5,413	$ 1,753
Obligations Under Capital Leases		
Noncurrent Liability	$ 3,569	$ 1,113
Liability Due Within One Year	1,844	640
Total Obligations Under Capital Leases	$ 5,413	$ 1,753

Future minimum lease payments consisted of the following at December 31, 2010:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2011	$ 2,088	$ 791
2012	1,533	771
2013	1,284	728
2014	351	529
2015	300	399
Later Years	472	896
Total Future Minimum Lease Payments	$ 6,028	$ 4,114
Less Estimated Interest Element	615	
Estimated Present Value of Future Minimum Lease Payments	$ 5,413	

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. In December 2010, management signed a new master lease agreement with GE Capital Commercial Inc. (GE) to replace existing operating and capital leases with GE. These assets were included in existing master lease agreements that were to be terminated in 2011 since GE exercised the termination provision related to these leases in 2008. Certain assets were not included in the refinancing, but the assets will be purchased or refinanced in 2011. In addition, certain operating leases that were previously under lease with GE are now recorded as capital leases after the refinancing. The amounts refinanced for KPCo are as follows:

Leases Refinanced with GE	KPCo
	(in thousands)
Operating Lease to Operating Lease	$ 3,246
Capital Lease to Capital Lease	314
Operating Lease to Capital Lease	1,142

These obligations are included in the future minimum lease payments schedule earlier in this note.

For equipment under the GE master lease agreements, the lessor is guaranteed receipt of up to 84% of the unamortized balance of the equipment at the end of the lease term. If the fair value of the leased equipment is below the unamortized balance at the end of the lease term, KPCo is committed to pay the difference between the fair value and the unamortized balance, with the total guarantee not to exceed 84% of the unamortized balance. For equipment under other master lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, KPCo is committed to pay the difference between the actual fair value and the residual value guarantee. At December 31, 2010, the maximum potential loss for these lease agreements was approximately $481 thousand ($312 thousand net of tax) assuming the fair value of the equipment is zero at the end of the lease term. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance.

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, 2010 and 2009:

Type of Debt	Maturity	Weighted Average Interest rate at December 31, 2010	Interest Rate Ranges at December 31, 2010	Interest Rate Ranges at December 31, 2009	Outstanding at December 31, 2010	Outstanding at December 31, 2009
					(in thousands)	
Senior Unsecured Notes	2017-2039	6.40%	5.625%-8.13%	5.625%-8.13%	$ 530,000	$ 530,000
Notes Payable - Affiliated	2015	5.25%	5.25%	5.25%	20,000	20,000
Unamortized Discount (net)					(1,112)	(1,278)
Total Long-term Debt Outstanding					548,888	548,722
Less Portion Due Within One Year					-	-
Long-term Portion					$ 548,888	$ 548,722

Long-term debt outstanding at December 31, 2010 is payable as follows:

	2011	2012	2013	2014	2015	After 2015	Total
				(in thousands)			
Principal Amount	$ -	$ -	$ -	$ -	$ 20,000	$ 530,000	$ 550,000
Unamortized Discount							(1,112)
Total Long-term Debt Outstanding							$ 548,888

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 KPCo to pay dividends out of retained earnings.

Leverage Restrictions

Pursuant to credit agreement leverage restrictions, at December 31, 2010, none of the retained earnings of KPCo have restrictions related to the payment of dividends.

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding loans (borrowings) to/from the Utility Money Pool as of December 31, 2010 and 2009 is included in Advances to/from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the years ended December 31, 2010 and 2009 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	Loans (Borrowings) to/from Utility Money Pool as of December 31,	Authorized Short-Term Borrowing Limit
			(in thousands)			
2010	$ 18,963	$ 69,599	$ 5,857	$ 25,995	$ 67,060	$ 250,000
2009	174,108	19,775	113,764	7,589	(485)	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, 2010, 2009 and 2008 are summarized in the following table:

Year Ended December 31,	Maximum Interest Rates for Funds Borrowed from Utility Money Pool	Minimum Interest Rates for Funds Borrowed from Utility Money Pool	Maximum Interest Rates for Funds Loaned to Utility Money Pool	Minimum Interest Rates for Funds Loaned to Utility Money Pool	Average Interest Rates for Funds Borrowed from Utility Money Pool	Average Interest Rates for Funds Loaned to Utility Money Pool
2010	0.55 %	0.09 %	0.53 %	0.09 %	0.38 %	0.31 %
2009	2.28 %	0.18 %	0.63 %	0.15 %	1.33 %	0.35 %
2008	5.47 %	2.28 %	- %	- %	3.42 %	- %

Interest expense and interest income related to the Utility Money Pool are included in Interest Expense and Interest Income, respectively, on 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, 2010, 2009 and 2008:

	Years Ended December 31, 2010	2009	2008
		(in thousands)	
Interest Expense	$ 10	$ 983	$ 1,893
Interest Income	49	18	-

Credit Facilities

In June 2010, KPCo and certain other companies in the AEP System reduced a $627 million credit agreement that matures in April 2011 to $478 million. Under the facility, letters of credit may be issued. As of December 31, 2010, there were no outstanding amounts for KPCo under the facility.

Sale of Receivables – AEP Credit

Under a sale of receivables 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's financing costs, administrative costs and uncollectible accounts experience for KPCo's receivables. The costs of customer accounts receivable sold are reported in Other Operation on KPCo's income statement. KPCo manages and services its accounts receivable sold.

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

KPCo's amount of accounts receivable and accrued unbilled revenues sold under the sale of receivables agreement was $63 million, $41 million and $56 million as of December 31, 2010, 2009 and 2008, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold were $2 million, $2 million and $3 million for the years ended December 31, 2010, 2009 and 2008, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit were $548 million, $500 million and $485 million as of December 31, 2010, 2009 and 2008, 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 MLR, 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 December 2010, each AEP Power Pool member gave notice to AEPSC and the other AEP Power Pool members of its decision to terminate the Interconnection Agreement effective January 2014 or such other date approved by the FERC. It is unknown at this time what will replace the Interconnection Agreement. 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, 2010, 2009 and 2008:

Related Party Revenues	Years Ended December 31, 2010	2009	2008
		(in thousands)	
Sales to AEP Power Pool	$ 57,777	$ 64,074	$ 62,642
Direct Sales to West Affiliates	711	454	3,521
Direct Sales to Transmission Companies	737	-	-
Natural Gas Contracts with AEPES	(435)	(1,823)	(133)
Other Revenues	1,215	(92)	219
Total Affiliated Revenues	$ 60,005	$ 62,613	$ 66,249

The following table shows the purchased power expense incurred from purchases from the pools and affiliates for the years ended December 31, 2010, 2009 and 2008:

Related Party Purchases	Years Ended December 31, 2010	2009	2008
		(in thousands)	
Purchases from AEP Power Pool	$ 107,199	$ 96,284	$ 127,669
Direct Purchases from West Affiliates	169	305	454
Purchases from AEGCo	101,032	101,731	106,256
Total Purchases	$ 208,400	$ 198,320	$ 234,379

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 MLR. The FERC approved a new TA effective November 2010. The impacts of the new TA will be phased-in for retail rates, adds KGPCo and WPCo as parties to the agreement and changes the allocation method.

KPCo's net credits as allocated under the TA during the years ended December 31, 2010, 2009 and 2008 were $8 million, $9 million and $2 million, respectively, and were recorded in Other Operation expense on KPCo's Statements of Income.

PSO, SWEPCo, TCC, TNC and AEPSC are parties to the TCA, originally dated January 1, 1997, as amended. 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. The agreement between AEPSC and AEPES ended December 31, 2010, coinciding with the settlement of the remaining DETM contracts. KPCo's risk management liabilities related to DETM at December 31, 2009 was $550 thousand.

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 $195 thousand, $88 thousand and $257 thousand for the years ended December 31, 2010, 2009 and 2008, 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 pays 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 $133 thousand, $112 thousand and $9 thousand in 2010, 2009 and 2008, respectively, for urea transloading provided by I&M. These costs were recorded as fuel expense or other 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 $368 thousand, $358 thousand and $1.2 million for the years ended December 31, 2010, 2009 and 2008, 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, 2010, 2009 and 2008 were $837 thousand, $340 thousand and $36 thousand, respectively.

Affiliate Railcar Agreement

KPCo has an agreement providing for the use its 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 recorded these costs 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:

	December 31,	
Billing Company	**2010**	**2009**
	(in thousands)	
APCo	$ 399	$ 669
OPCo	245	13

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 for the year ended December 31, 2008.

In January 2010, the AEP Power Pool began purchasing power from OVEC to serve off-system sales and retail sales through June 2010. Purchases serving off-system sales are reported net as a reduction in Electric Generation, Transmission and Distribution revenues and purchases serving retail sales are reported in Purchased Electricity for Resale expenses on KPCo's Statement of Income. KPCo recorded $1.4 million in revenue and $743 thousand in expense for the year ended December 31, 2010.

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, 2010, 2009 and 2008 as shown in the following table:

	Years Ended December 31,		
Companies	**2010**	**2009**	**2008**
		(in thousands)	
APCo to KPCo	$ 209	$ -	$ -
CSP to KPCo	433	-	-
I&M to KPCo	-	-	444
OPCo to KPCo	527	-	-

In addition, KPCo had aggregate affiliated sales and purchases of meters and transformers for the years ended December 31, 2010, 2009 and 2008 as shown in the following table:

	APCo	**CSPCo**	**I&M**	**KGPCo**	**OPCo**	**PSO**	**SWEPCo**	**TCC**	**WPCo**	**Total**
Sales					(in thousands)					
2010	$ 364	$ 9	$ 6	$ 23	$ 83	$ -	$ 2	$ -	$ -	$ 487
2009	505	23	64	7	133	3	8	-	1	744
2008	354	11	16	6	121	-	2	33	-	543
Purchases										
2010	139	-	7	-	139	-	3	-	-	288
2009	161	-	50	-	87	-	26	-	-	324
2008	112	-	15	-	95	-	-	-	-	222

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

Global Borrowing Notes

AEP has an intercompany note in place with KPCo. The debt is reflected in Long-term Debt – Affiliated on KPCo's Balance Sheets. 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 participates in the global borrowing arrangement.

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 if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether 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, power to direct the VIE and other factors. Management believes that 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.

AEPSC provides certain managerial and professional services to KPCo and other subsidiaries. AEP is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to KPCo and other subsidiaries at AEPSC's cost. KPCo and other subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and KPCo and other subsidiaries that could require additional financial support from KPCo and other 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 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 AEPSC due to its activity in AEPSC's cost reimbursement structure. However, KPCo does not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. Total billings from AEPSC for the years ended December 31, 2010, 2009 and 2008 were $37 million, $34 million and $46 million, respectively. The carrying amount of liabilities associated with AEPSC for the years ended December 31, 2010 and 2009 were $3 million and $4 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 AEP management's control over AEGCo, KPCo is not considered the primary beneficiary of AEGCo. 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, 2010, 2009 and 2008 were $101 million, $102 million and $106 million, respectively. The carrying amount of liabilities associated with AEGCo for the years ended December 31, 2010 and 2009 was $10 million and $9 million, respectively. 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:

2010	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ 553,589	$ 200,199	3.8%	40-50	$ -	$ -	-	-
Transmission	444,303	148,466	1.7%	25-75	-	-	-	-
Distribution	590,606	171,092	3.5%	11-75	-	-	-	-
CWIP	34,093	(880)	N.M.	N.M.	-	-	-	-
Other	58,282	23,371	8.3%	N.M.	5,700	195	N.M.	N.M.
Total	$ 1,680,873	$ 542,248			$ 5,700	$ 195		

2009	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ 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	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Generation	3.5%	40-50	-	-
Transmission	1.6%	25-75	-	-
Distribution	3.4%	11-75	-	-
CWIP	N.M.	N.M.	-	-
Other	8.1%	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 2010 and 2009 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)			
2010	$ 3,506	$ 292	$ 823	$ (435)	$ -	$ 4,186
2009	3,275	297	-	(66)	-	3,506

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, 2010	2009	2008
		(in thousands)	
Allowance for Equity Funds Used During Construction	$ 768	$ 391	$ 1,012
Allowance for Borrowed Funds Used During Construction	594	394	1,701

14. COST REDUCTION INITIATIVES

In April 2010, management began initiatives to decrease both labor and non-labor expenses with a goal of achieving significant reductions in operation and maintenance expenses. A total of 2,461 positions were eliminated across the AEP System as a result of process improvements, streamlined organizational designs and other efficiencies. Most of the affected employees terminated employment on May 31, 2010. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

KPCo recorded a charge to expense in 2010 primarily related to the headcount reduction initiatives. Management does not expect additional costs to be incurred related to this initiative.

Expense Allocation from AEPSC	Incurred	Settled	Adjustments	Remaining Balance at December 31, 2010
		(in thousands)		
$ 3,481	$ 8,175	$ 12,001	$ 1,363	$ 1,018

These costs relate primarily to severance benefits. They are included primarily in Other Operation on the Statements of Income and Other Current Liabilities on the Balance Sheets.

15. 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:

	2010 Quarterly Periods Ended			
	March 31	**June 30**	**September 30**	**December 31**
	(in thousands)			
Total Revenues	$ 173,918	$ 136,972	$ 189,417 (b)	$ 183,365 (b)
Operating Income (Loss)	24,680	(2,831)(a)	33,326 (b)	33,680 (b)
Net Income (Loss)	9,491	(7,045)(a)	15,945 (b)	16,891 (b)

	2009 Quarterly Periods Ended			
	March 31	**June 30**	**September 30**	**December 31**
	(in thousands)			
Total 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

(a) See Note 14 for discussion of expenses related to cost reduction initiatives recorded in the second quarter of 2010.
(b) See "Kentucky Base Rate Filing" section of Note 2 for discussion of new base rates in effect.

There were no significant events in 2009.