Kentucky Power Company

2011 Annual Report

Audited Financial Statements

AEP AMERICAN® ELECTRIC POWER

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GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East companies	APCo, 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, 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.
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.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company.
ERCOT	Electric Reliability Council of Texas regional transmission organization.
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 utility 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.
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.

Term	Meaning
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 regional transmission organization.
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 utility 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, 2011 and 2010, and the related statements of income, comprehensive income (loss), changes in common shareholder’s equity, and cash flows for each of the three years in the period ended December 31, 2011. 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, 2011 and 2010, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the financial statements, in 2011 the Company changed its method of presenting comprehensive income due to the adoption of FASB Accounting Standards Update No. 2011-05, *Comprehensive Income (Topic 220): Presentation of Comprehensive Income*. The change in presentation has been applied retrospectively to all periods presented.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2012

KENTUCKY POWER COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2011, 2010 and 2009
(in thousands)

	2011	2010	2009
REVENUES			
Electric Generation, Transmission and Distribution	$ 656,191	$ 623,100	$ 567,564
Sales to AEP Affiliates	72,259	60,005	62,613
Other Revenues	494	567	2,349
TOTAL REVENUES	728,944	683,672	632,526
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	211,246	185,938	188,525
Purchased Electricity for Resale	23,924	21,422	24,839
Purchased Electricity from AEP Affiliates	213,665	208,400	198,320
Other Operation	63,323	68,972	51,417
Maintenance	51,354	46,223	38,888
Depreciation and Amortization	53,756	52,867	52,010
Taxes Other Than Income Taxes	11,700	10,995	11,738
TOTAL EXPENSES	628,968	594,817	565,737
OPERATING INCOME	99,976	88,855	66,789
Other Income (Expense):			
Interest Income	2,324	239	218
Allowance for Equity Funds Used During Construction	1,229	768	391
Interest Expense	(36,411)	(36,442)	(33,812)
INCOME BEFORE INCOME TAX EXPENSE	67,118	53,420	33,586
Income Tax Expense	24,744	18,138	9,650
NET INCOME	$ 42,374	$ 35,282	$ 23,936

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

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2011, 2010 and 2009
(in thousands)

	2011	2010	2009
NET INCOME	$ 42,374	$ 35,282	$ 23,936
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $94 in 2011, $81 in 2010 and $355 in 2009	(174)	150	(660)
TOTAL COMPREHENSIVE INCOME	$ 42,200	$ 35,432	$ 23,276

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2011, 2010 and 2009
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
NET INCOME			23,936		23,936
OTHER COMPREHENSIVE LOSS				(660)	(660)
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
NET INCOME			35,282		35,282
OTHER COMPREHENSIVE INCOME				150	150
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2010	50,450	238,750	157,467	(451)	446,216
Common Stock Dividends			(28,000)		(28,000)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					418,216
NET INCOME			42,374		42,374
OTHER COMPREHENSIVE LOSS				(174)	(174)
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2011	$ 50,450	$ 238,750	$ 171,841	$ (625)	$ 460,416

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
BALANCE SHEETS
ASSETS
December 31, 2011 and 2010
(in thousands)

	2011	2010
CURRENT ASSETS		
Cash and Cash Equivalents	$ 778	$ 281
Advances to Affiliates	70,332	67,060
Accounts Receivable:		
Customers	15,445	21,652
Affiliated Companies	9,441	17,616
Accrued Unbilled Revenues	3,379	3,823
Miscellaneous	1,926	587
Allowance for Uncollectible Accounts	(622)	(623)
Total Accounts Receivable	29,569	43,055
Fuel	23,006	16,640
Materials and Supplies	27,152	24,378
Risk Management Assets	8,388	8,697
Accrued Tax Benefits	11	1,420
Margin Deposits	3,409	5,357
Prepayments and Other Current Assets	2,975	1,497
TOTAL CURRENT ASSETS	165,620	168,385
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	554,218	553,589
Transmission	456,552	444,303
Distribution	612,832	590,606
Other Property, Plant and Equipment	60,390	63,982
Construction Work in Progress	71,290	34,093
Total Property, Plant and Equipment	1,755,282	1,686,573
Accumulated Depreciation and Amortization	573,871	542,443
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,181,411	1,144,130
OTHER NONCURRENT ASSETS		
Regulatory Assets	214,860	213,593
Long-term Risk Management Assets	8,300	8,030
Deferred Charges and Other Noncurrent Assets	23,793	37,946
TOTAL OTHER NONCURRENT ASSETS	246,953	259,569
TOTAL ASSETS	$ 1,593,984	$ 1,572,084

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
December 31, 2011 and 2010

	2011	2010
	(in thousands)	
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 36,076	$ 33,334
Affiliated Companies	35,131	45,790
Risk Management Liabilities	5,629	5,959
Customer Deposits	22,074	19,692
Accrued Taxes	19,436	23,741
Accrued Interest	7,754	7,570
Other Current Liabilities	26,520	26,227
TOTAL CURRENT LIABILITIES	152,620	162,313
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	529,055	528,888
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	2,734	2,303
Deferred Income Taxes	338,656	316,389
Regulatory Liabilities and Deferred Investment Tax Credits	31,562	34,991
Employee Benefits and Pension Obligations	48,007	49,298
Deferred Credits and Other Noncurrent Liabilities	10,934	11,686
TOTAL NONCURRENT LIABILITIES	980,948	963,555
TOTAL LIABILITIES	1,133,568	1,125,868
Rate Matters (Note 3)		
Commitments and Contingencies (Note 5)		
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	171,841	157,467
Accumulated Other Comprehensive Income (Loss)	(625)	(451)
TOTAL COMMON SHAREHOLDER'S EQUITY	460,416	446,216
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 1,593,984	$ 1,572,084

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2011, 2010 and 2009
(in thousands)

	2011	2010	2009
OPERATING ACTIVITIES			
Net Income	$ 42,374	$ 35,282	$ 23,936
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	53,756	52,867	52,010
Deferred Income Taxes	17,766	1,075	50,612
Deferral of Storm Costs	-	-	(24,355)
Allowance for Equity Funds Used During Construction	(1,229)	(768)	(391)
Mark-to-Market of Risk Management Contracts	(220)	5,651	(2,386)
Pension Contributions to Qualified Plan Trust	(10,535)	(6,184)	-
Fuel Over/Under-Recovery, Net	2,274	(923)	11,740
Change in Other Noncurrent Assets	(4,231)	7,084	1,452
Change in Other Noncurrent Liabilities	1,564	(4,619)	(2,943)
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	15,029	(12,035)	(444)
Fuel, Materials and Supplies	(7,434)	14,512	(13,643)
Accounts Payable	(11,556)	11,228	(7,149)
Accrued Taxes, Net	(2,553)	37,721	(29,470)
Other Current Assets	464	1,514	(1,177)
Other Current Liabilities	4,547	1,198	(2,997)
Net Cash Flows from Operating Activities	100,016	143,603	54,795
INVESTING ACTIVITIES			
Construction Expenditures	(65,898)	(54,058)	(63,963)
Change in Advances to Affiliates, Net	(3,272)	(67,060)	-
Acquisitions of Assets	(1,289)	(254)	(316)
Proceeds from Sales of Assets	439	700	927
Net Cash Flows Used for Investing Activities	(70,020)	(120,672)	(63,352)
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)
Principal Payments for Capital Lease Obligations	(1,551)	(1,674)	(749)
Dividends Paid on Common Stock	(28,000)	(21,000)	(19,500)
Other Financing Activities	52	15	276
Net Cash Flows from (Used for) Financing Activities	(29,499)	(23,144)	8,405
Net Increase (Decrease) in Cash and Cash Equivalents	497	(213)	(152)
Cash and Cash Equivalents at Beginning of Period	281	494	646
Cash and Cash Equivalents at End of Period	$ 778	$ 281	$ 494
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 36,098	$ 35,838	$ 37,402
Net Cash Paid (Received) for Income Taxes	7,785	(16,700)	(8,713)
Noncash Acquisitions Under Capital Leases	264	4,202	829
Construction Expenditures Included in Current Liabilities at December 31,	7,446	3,411	5,451

See Notes to Financial Statements beginning on page 10.

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 173,000 retail customers in its service territory in eastern Kentucky. KPCo also sells power at wholesale to municipalities.

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. APCo's Dresden Plant was completed in January 2012. The addition of the Dresden Plant and removal of OPCo's Sporn Unit 5 will change the capacity reserve relationship of the AEP Power Pool members.

The AEP East companies are parties to a Transmission Agreement defining how they share the revenues and 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 transactions with 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 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.

Applications to Amend Sharing Agreements

Based upon the PUCO's January 2012 approval of OPCo's corporate separation plan, applications were filed in February 2012 with the FERC proposing to establish a new power cost sharing agreement between APCo, I&M and KPCo and transfer OPCo's generation assets to APCo, KPCo and a nonregulated AEP subsidiary. In conjunction with these filings, APCo and KPCo, which are generation capacity deficit utilities, filed an application with the FERC to acquire approximately 2,400 MWs of OPCo's 12,000 MW generation capacity at net book value. This acquisition would allow APCo and KPCo to satisfy their capacity reserve requirements in PJM and provide baseload generation to meet their customers' energy requirements. The Ohio corporate separation plan was subsequently rejected on rehearing in February 2012. Management is in the process of withdrawing the applications.

If KPCo experiences decreases in revenues or increases in costs as a result of changes to its relationship with affiliates and is unable to recover the change in revenues and costs through rates, prices or additional sales, it could have an adverse impact on future net income and cash flows.

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. Wholesale power transactions 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. The KPSC also regulates 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 on the balance sheets, 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 12 for additional information.

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense related to receivables purchased from KPCo under a sale of receivables agreement. 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, 2011.

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." When it becomes probable that an asset in service or an asset under construction will be abandoned and regulatory cost recovery has been disallowed, the cost of that asset shall be removed from plant-in-service or CWIP and charged to expense.

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

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

AEP utilizes its trustee's external pricing service 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 management performs its own valuation testing to verify the fair values of the securities. AEP receives audit reports of the trustee's operating controls and valuation processes. The trustee uses multiple pricing vendors for the assets held in the trusts.

Assets in the benefits trusts 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. Items classified as Level 2 are primarily investments in individual fixed income securities and cash equivalents funds. Fixed income securities do not trade on an exchange and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. 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 primarily real estate and private equity investments that are valued using methods requiring judgment including appraisals.

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. Fuel cost over-recoveries (the excess of fuel revenues billed to customers over applicable fuel costs incurred) are generally deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel revenues billed to customers) are generally 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. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when there is a phase-in plan or the FAC has been suspended or terminated. 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 given to 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 sheets. 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 on the statements of income 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 on 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 in which KPCo participates 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 when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting. KPCo 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 OTC 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 on 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 AOCI into revenues or expenses within the same financial statement line item as the forecasted transaction on the 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 8.

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 allocations and periodically rebalances the investments to targeted allocations 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 levels.
- 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 investment policy for the pension fund allocates assets based on the funded status of the pension plan. The objective of the asset allocation policy is to reduce the investment volatility of the plan over time. Generally, more of the investment mix will be allocated to fixed income investments as the plan becomes better funded. Assets will be transferred away from equity investments into fixed income investments based on the market value of plan assets compared to the plan's projected benefit obligation. The current target asset allocations are as follows:

Pension Plan Assets	Target
Equity	45.0 %
Fixed Income	45.0 %
Other Investments	10.0 %

OPEB Plans Assets	Target
Equity	66.0 %
Fixed Income	33.0 %
Cash	1.0 %

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.
- No individual stock may be more 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
- 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 eleven 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).

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, 2011 and 2010 are shown in the following table:

	December 31,	
Components	**2011**	**2010**
	(in thousands)	
Cash Flow Hedges, Net of Tax	$ (625)	$ (451)

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 28, 2012, the date that KPCo’s 2011 annual report was issued.

2. <u>NEW ACCOUNTING PRONOUNCEMENTS</u>

Management reviews the new accounting literature to determine its relevance, if any, to KPCo’s business. The following represents a summary of final pronouncements that impact the financial statements.

<u>Pronouncements Adopted During 2011</u>

The following standards were adopted during 2011. Consequently, their impact is reflected in the financial statements. The following paragraphs discuss their impact.

ASU 2011-05 “Presentation of Comprehensive Income” (ASU 2011-05)

KPCo adopted ASU 2011-05 effective for the 2011 Annual Report. The standard requires other comprehensive income be presented as part of a single continuous statement of comprehensive income or in a statement of other comprehensive income immediately following the statement of net income.

This standard requires retrospective application to all reporting periods presented in the financial statements. This standard changed the presentation of the financial statements but did not affect the calculation of net income or comprehensive income. The FASB deferred the reclassification adjustment presentation provisions of ASU 2011-05 under the terms in ASU 2011-12, "Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income."

3. 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.

Carbon Capture and Sequestration Project with the Department of Energy (DOE) (Commercial Scale Project)

During 2010, AEPSC, on behalf of APCo, began the project definition stage for the potential construction of a new commercial scale CCS facility at the Mountaineer Plant. The DOE agreed to fund 50% of allowable costs incurred for the CCS facility up to a maximum of $334 million. A Front-End Engineering and Design (FEED) study was completed during the third quarter of 2011. Management postponed any further CCS project activities because of the uncertainty about the regulation of CO_2. In June 2011, the FEED study costs were allocated among the AEP East companies, PSO and SWEPCo based on eligible plants that could potentially benefit from the carbon capture. As of December 31, 2011, APCo has incurred $34 million in total project costs and has received $20 million of DOE and other eligible funding resulting in $14 million of net costs, of which $8 million was written off. The remaining $6 million in net costs are recorded in Regulatory Assets on the balance sheet. KPCo's portion of remaining net costs is $905 thousand at December 31, 2011. If the costs of the CCS project cannot be recovered, it would reduce future net income and cash flows.

FERC Rate Matters

Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund

In 2004, AEP eliminated transaction-based through-and-out transmission service charges and collected, at the FERC's direction, load-based charges, referred to as RTO SECA through March 2006. Intervenors objected and 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. KPCo's portion of recognized gross SECA revenues was $17 million. In 2006, a FERC Administrative Law Judge 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.

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 required a compliance filing to be filed with the FERC by August 2010. 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, 2011 was $32 million. KPCo's portion of the reserve balance as of December 31, 2011 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 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 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.

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. In June 2011, the FERC approved the settlement agreement.

Possible Termination of the Interconnection Agreement

In December 2010, each of the AEP Power Pool members gave notice to AEPSC and each other of their decision to terminate the Interconnection Agreement effective January 2014 or such other date approved by FERC, subject to state regulatory input. In February 2012, an application was filed with the FERC proposing to establish a new power cost sharing agreement between APCo, I&M and KPCo. If any of the AEP Power Pool members experience decreases in revenues or increases in costs as a result of the termination of the AEP Power Pool and are unable to recover the change in revenues and costs through rates, prices or additional sales, it could reduce future net income and cash flows. As a result of the February 2012 Ohio Electric Security Plan rehearing order issued by the Public Utilities Commission of Ohio, management is in the process of withdrawing the FERC applications.

4. EFFECTS OF REGULATION

Regulatory assets and liabilities are comprised of the following items:

Regulatory Assets:	December 31, 2011	2010	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			
Mountaineer Carbon Capture and Storage Commercial Scale Facility	$ 905	$ -	
Total Regulatory Assets Not Yet Being Recovered	905	-	
Regulatory assets being recovered:			
Regulatory Assets Currently Earning a Return			
RTO Formation/Integration Costs	1,194	1,373	8 years
Unamortized Loss on Reacquired Debt	704	737	21 years
Regulatory Assets Currently Not Earning a Return			
Income Taxes, Net	122,822	123,789	22 years
Pension and OPEB Funded Status	66,392	58,853	13 years
Storm Related Costs	16,445	21,143	4 years
Postemployment Benefits	5,205	6,456	4 years
Other Regulatory Assets Being Recovered	1,193	1,242	various
Total Regulatory Assets Being Recovered	213,955	213,593	
Total Noncurrent Regulatory Assets	$ 214,860	$ 213,593	

Regulatory Liabilities:	December 31, 2011	2010	Remaining Refund Period
	(in thousands)		
Current Regulatory Liability			
Over-recovered Fuel Costs - does not pay a return	$ 3,138	$ 864	1 year
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	27,125	27,975	(a)
Regulatory Liabilities Currently Not Paying a Return			
Unrealized Gain on Forward Commitments	3,536	5,844	5 years
Deferred Investment Tax Credits	634	993	9 years
Other Regulatory Liabilities Being Paid	267	179	various
Total Regulatory Liabilities Being Paid	31,562	34,991	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 31,562	$ 34,991	

(a) Relieved as removal costs are incurred.

5. 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

Construction and 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 $110 million of construction expenditures, excluding equity AFUDC, for 2012. 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, 2011:

Contractual Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
			(in thousands)		
Fuel Purchase Contracts (a)	$ 176,581	$ 77,077	$ 3,865	$ -	$ 257,523
Energy and Capacity Purchase Contracts (b)	353	202	107	-	662
Construction Contracts for Capital Assets (c)	491	-	-	-	491
Total	$ 177,425	$ 77,279	$ 3,972	$ -	$ 258,676

(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.
(c) Represents only capital assets for which there are signed contracts. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs.

GUARANTEES

Liabilities for guarantees are recorded in accordance with the accounting guidance for "Guarantees." There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties.

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of December 31, 2011, there were no material liabilities recorded for any indemnifications.

KPCo is jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies related to purchase power and sale activity pursuant to the SIA.

Lease Obligations

KPCo leases certain equipment under master lease agreements. See "Master Lease Agreements" section of Note 11 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. Insurance coverage includes 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. In 2010, the U.S. Supreme Court granted the defendants' petition for review. In June 2011, the U.S. Supreme Court reversed and remanded the case to the Court of Appeals, finding that plaintiffs' federal common law claims are displaced by the regulatory authority granted to the Federal EPA under the CAA. After the remand, the plaintiffs asked the Second Circuit to return the case to the district court so that they could withdraw their complaints. The cases were returned to the district court and the plaintiffs' federal common law claims were dismissed in December 2011.

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. Plaintiffs refiled their complaint in federal district court. The court ordered all defendants to respond to the refiled complaints in October 2011. Management believes the claims are without merit, and in addition to other defenses, are barred by the doctrine of collateral estoppel and the applicable statute of limitations. Management intends to defend against the claims. 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. 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. The court accepted supplemental briefing on the impact of the Supreme Court's decision and heard oral argument in November 2011. 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, 2011, there is one site for which KPCo has received an information request which could lead to a Potentially Responsible Party designation. In the instance where KPCo has been named a defendant, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

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

6. 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 Plan		Other Postretirement Benefit Plans	
Assumptions	**2011**	**2010**	**2011**	**2010**
Discount Rate	4.55 %	5.05 %	4.75 %	5.25 %
Rate of Compensation Increase	4.50 % (a)	4.55 % (a)	NA	NA

(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.

NA 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 2011, 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 4.5%.

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 Plan			Other Postretirement Benefit Plans		
	2011	**2010**	**2009**	**2011**	**2010**	**2009**
Discount Rate	5.05 %	5.60 %	6.00 %	5.25 %	5.85 %	6.10 %
Expected Return on Plan Assets	7.75 %	8.00 %	8.00 %	7.50 %	8.00 %	7.75 %
Rate of Compensation Increase	4.50 %	4.20 %	5.50 %	NA	NA	NA

NA Not Applicable

The expected return on plan assets for 2011 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	2011	2010
Initial	7.50 %	8.00 %
Ultimate	5.00 %	5.00 %
Year Ultimate Reached	2016	2016

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	$ 578	$ (461)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	7,216	(5,889)

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, 2011, 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, 2011 and 2010

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 Plan		Other Postretirement Benefit Plans	
	2011	2010	2011	2010
Change in Benefit Obligation	(in thousands)			
Benefit Obligation at January 1	$ 113,592	$ 108,511	$ 56,806	$ 50,826
Service Cost	1,389	2,549	939	1,060
Interest Cost	5,757	5,900	2,913	2,953
Actuarial Loss	7,172	7,073	7,046	4,964
Plan Amendment Prior Service Credit	-	-	(5,440)	(679)
Benefit Payments	(6,535)	(10,441)	(3,366)	(3,163)
Participant Contributions	-	-	773	649
Medicare Subsidy	-	-	190	196
Benefit Obligation at December 31	$ 121,375	$ 113,592	$ 59,861	$ 56,806
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 88,666	$ 81,637	$ 40,766	$ 35,553
Actual Gain (Loss) on Plan Assets	7,967	11,286	(248)	5,134
Company Contributions	10,535	6,184	1,814	2,593
Participant Contributions	-	-	773	649
Benefit Payments	(6,535)	(10,441)	(3,366)	(3,163)
Fair Value of Plan Assets at December 31	$ 100,633	$ 88,666	$ 39,739	$ 40,766
Underfunded Status at December 31	$ (20,742)	$ (24,926)	$ (20,122)	$ (16,040)

Amounts Recognized on the Balance Sheets as of December 31, 2011 and 2010

	Pension Plan		Other Postretirement Benefit Plans	
	December 31,			
	2011	2010	2011	2010
	(in thousands)			
Employee Benefits and Pension Obligations - Accrued Long-term Benefit Liability	$ (20,742)	$ (24,926)	$ (20,122)	$ (16,040)
Underfunded Status	$ (20,742)	$ (24,926)	$ (20,122)	$ (16,040)

Amounts Included in Regulatory Assets as of December 31, 2011 and 2010

	Pension Plan		Other Postretirement Benefit Plans	
	December 31,			
	2011	2010	2011	2010
Components	(in thousands)			
Net Actuarial Loss	$ 45,998	$ 42,392	$ 25,941	$ 16,453
Prior Service Cost (Credit)	279	429	(5,826)	(421)
Recorded as				
Regulatory Assets	$ 46,277	$ 42,821	$ 20,115	$ 16,032

Components of the change in amounts included in Regulatory Assets during the years ended December 31, 2011 and 2010 are as follows:

	Pension Plan		Other Postretirement Benefit Plans	
	Years Ended December 31,			
	2011	2010	2011	2010
Components	(in thousands)			
Actuarial Loss During the Year	$ 6,557	$ 3,441	$ 10,239	$ 2,665
Prior Service Credit	-	-	(5,440)	(679)
Amortization of Actuarial Loss	(2,951)	(2,052)	(751)	(732)
Amortization of Prior Service Credit (Cost)	(150)	(150)	35	-
Amortization of Transition Obligation	-	-	-	(488)
Change for the Year	$ 3,456	$ 1,239	$ 4,083	$ 766

Pension and Other Postretirement Plans' Assets

The following table presents the classification of pension plan assets within the fair value hierarchy at December 31, 2011:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 34,021	$ -	$ -	$ -	$ 34,021	33.8 %
International	9,327	-	-	-	9,327	9.3 %
Real Estate Investment Trusts	2,432	-	-	-	2,432	2.4 %
Common Collective Trust - International	-	3,004	-	-	3,004	3.0 %
Subtotal - Equities	45,780	3,004	-	-	48,784	48.5 %
Fixed Income:						
Common Collective Trust - Debt	-	614	-	-	614	0.6 %
United States Government and Agency Securities	-	13,231	-	-	13,231	13.2 %
Corporate Debt	-	23,028	149	-	23,177	23.0 %
Foreign Debt	-	4,459	-	-	4,459	4.4 %
State and Local Government	-	1,124	-	-	1,124	1.1 %
Other - Asset Backed	-	608	-	-	608	0.6 %
Subtotal - Fixed Income	-	43,064	149	-	43,213	42.9 %
Real Estate	-	-	3,820	-	3,820	3.8 %
Alternative Investments	-	-	3,750	-	3,750	3.7 %
Securities Lending	-	5,023	-	-	5,023	5.0 %
Securities Lending Collateral (a)	-	-	-	(5,514)	(5,514)	(5.5)%
Cash and Cash Equivalents	-	2,170	-	-	2,170	2.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	(613)	(613)	(0.6)%
Total	$ 45,780	$ 53,261	$ 7,719	$ (6,127)	$ 100,633	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 accrued interest, dividend receivables and transactions pending settlement.

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

	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
		(in thousands)		
Balance as of January 1, 2011	$ -	$ 1,912	$ 2,988	$ 4,900
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	531	218	749
Relating to Assets Sold During the Period	-	-	75	75
Purchases and Sales	-	1,377	469	1,846
Transfers into Level 3	149	-	-	149
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2011	$ 149	$ 3,820	$ 3,750	$ 7,719

The following table presents the classification of OPEB plan assets within the fair value hierarchy at December 31, 2011:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 9,804	$ -	$ -	$ -	$ 9,804	24.7 %
International	10,721	-	-	-	10,721	27.0 %
Common Collective Trust - Global	-	2,795	-	-	2,795	7.0 %
Subtotal - Equities	20,525	2,795	-	-	23,320	58.7 %
Fixed Income:						
Common Collective Trust - Debt	-	1,951	-	-	1,951	4.9 %
United States Government and Agency Securities	-	2,277	-	-	2,277	5.7 %
Corporate Debt	-	4,288	-	-	4,288	10.8 %
Foreign Debt	-	909	-	-	909	2.3 %
State and Local Government	-	237	-	-	237	0.6 %
Other - Asset Backed	-	54	-	-	54	0.1 %
Subtotal - Fixed Income	-	9,716	-	-	9,716	24.4 %
Trust Owned Life Insurance:						
International Equities	-	1,303	-	-	1,303	3.3 %
United States Bonds	-	4,449	-	-	4,449	11.2 %
Cash and Cash Equivalents	474	660	-	-	1,134	2.9 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	(183)	(183)	(0.5)%
Total	$ 20,999	$ 18,923	$ -	$ (183)	$ 39,739	100.0 %

(a) 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, 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.

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, 2011	2010
	(in thousands)	
Qualified Pension Plan	$ 119,973	$ 112,820
Total	$ 119,973	$ 112,820

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, 2011 and 2010 were as follows:

	Underfunded Pension Plans	
	2011	2010
	(in thousands)	
Projected Benefit Obligation	$ 121,375	$ 113,592
Accumulated Benefit Obligation	$ 119,973	$ 112,820
Fair Value of Plan Assets	100,633	88,666
Underfunded Accumulated Benefit Obligation	$ (19,340)	$ (24,154)

Estimated Future Benefit Payments and Contributions

KPCo expects contributions for the pension plan of $6 million and the OPEB plans of $2.3 million during 2012. The estimated contributions to the pension trust are at least the minimum amount required by the Employee Retirement Income Security Act 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. In December 2011, the prescription drug plan was amended for certain participants. The impact of the change is reflected in the Benefit Plan Obligation table as a plan amendment. As a result of this amendment to the plan, the Medicare subsidy receipts in the following table are reduced from prior published estimates. 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 Plan	Other Postretirement Benefit Plans	
	Pension Payments	Benefit Payments	Medicare Subsidy Receipts
		(in thousands)	
2012	$ 6,903	$ 3,476	$ 183
2013	7,084	3,616	-
2014	7,393	3,792	-
2015	7,620	4,055	-
2016	8,303	4,343	-
Years 2017 to 2021, in Total	44,297	25,714	-

Components of Net Periodic Benefit Cost

The following table provides the components of net periodic benefit cost for the years ended December 31, 2011, 2010 and 2009:

	Pension Plan			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2011	2010	2009	2011	2010	2009
	(in thousands)					
Service Cost	$ 1,389	$ 2,549	$ 2,572	$ 939	$ 1,060	$ 971
Interest Cost	5,757	5,900	5,861	2,913	2,953	2,866
Expected Return on Plan Assets	(7,351)	(7,654)	(7,684)	(3,029)	(2,841)	(2,187)
Amortization of Transition Obligation	-	-	-	-	488	488
Amortization of Prior Service Cost (Credit)	150	150	151	(35)	-	-
Amortization of Net Actuarial Loss	2,951	2,052	1,318	751	732	1,094
Net Periodic Benefit Cost	2,896	2,997	2,218	1,539	2,392	3,232
Capitalized Portion	(1,121)	(1,064)	(825)	(596)	(849)	(1,202)
Net Periodic Benefit Cost Recognized as Expense	$ 1,775	$ 1,933	$ 1,393	$ 943	$ 1,543	$ 2,030

Estimated amounts expected to be amortized to net periodic benefit costs and the impact on the balance sheet during 2012 are shown in the following table:

Components	Pension Plan	Other Postretirement Benefit Plans
	(in thousands)	
Net Actuarial Loss	$ 3,529	$ 1,576
Prior Service Cost (Credit)	84	(504)
Total Estimated 2012 Amortization	$ 3,613	$ 1,072
Expected to be Recorded as		
Regulatory Asset	$ 3,613	$ 1,072
Total	$ 3,613	$ 1,072

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 are 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions. The cost for matching contributions totaled $1.4 million in 2011, $1.4 million in 2010 and $1.7 million in 2009.

7. BUSINESS SEGMENTS

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

8. 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, 2011 and 2010:

Notional Volume of Derivative Instruments

	Volume		
	December 31,		Unit of
Primary Risk Exposure	2011	2010	Measure
	(in thousands)		
Commodity:			
Power	35,858	40,277	MWHs
Coal	783	3,280	Tons
Natural Gas	1,676	449	MMBtus
Heating Oil and Gasoline	274	274	Gallons
Interest Rate	$ 6,566	$ 2,008	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 activities 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 future borrowings of fixed-rate debt. The forecasted 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 when 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, 2011 and 2010 balance sheets, KPCo netted $908 thousand and $400 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $6.1 million and $3.4 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, 2011 and 2010:

Fair Value of Derivative Instruments
December 31, 2011

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate (a)**	**Other (b)**	**Total**
		(in thousands)			
Current Risk Management Assets	$ 49,249	$ 221	$ -	$ (41,082)	$ 8,388
Long-term Risk Management Assets	21,107	18	-	(12,825)	8,300
Total Assets	70,356	239	-	(53,907)	16,688
Current Risk Management Liabilities	49,793	595	-	(44,759)	5,629
Long-term Risk Management Liabilities	17,362	74	-	(14,702)	2,734
Total Liabilities	67,155	669	-	(59,461)	8,363
Total MTM Derivative Contract Net Assets (Liabilities)	$ 3,201	$ (430)	$ -	$ 5,554	$ 8,325

Fair Value of Derivative Instruments
December 31, 2010

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate (a)**	**Other (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

(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 include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging." Amounts also include de-designated risk management contracts.

The table below presents KPCo's activity of derivative risk management contracts for the years ended December 31, 2011, 2010 and 2009:

Amount of Gain (Loss) Recognized on
Risk Management Contracts

Location of Gain (Loss)	Years Ended December 31, 2011	2010	2009
		(in thousands)	
Electric Generation, Transmission and Distribution Revenues	$ 2,248	$ 10,188	$ 20,402
Sales to AEP Affiliates	31	(1,272)	(2,162)
Fuel and Other Consumables Used for Electric Generation	(3)	-	-
Regulatory Assets (a)	93	(93)	-
Regulatory Liabilities (a)	(1,158)	(2,170)	(2,719)
Total Gain on Risk Management Contracts	$ 1,211	$ 6,653	$ 15,521

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

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. Unrealized and 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. Unrealized and 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. However, 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 2011, 2010 and 2009, 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 any 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 2011, 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 2011, 2010 and 2009, KPCo designated heating oil and gasoline derivatives as cash flow hedges.

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 2011, 2010 and 2009, KPCo did not designate any cash flow hedging strategies for interest rate derivative hedges.

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 2011, 2010 and 2009, KPCo did not employ any foreign currency hedging strategies.

During 2011, 2010 and 2009, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

The following tables provide details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's balance sheets and the reasons for changes in cash flow hedges for the years ended December 31, 2011, 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, 2011

	Commodity	Interest Rate	Total
		(in thousands)	
Balance in AOCI as of December 31, 2010	$ (48)	$ (403)	$ (451)
Changes in Fair Value Recognized in AOCI	(431)	-	(431)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Electric Generation, Transmission and Distribution Revenues	205	-	205
Purchased Electricity for Resale	51	-	51
Other Operation Expense	(32)	-	(32)
Maintenance Expense	(37)	-	(37)
Interest Expense	-	61	61
Property, Plant and Equipment	(47)	-	(47)
Regulatory Assets (a)	56	-	56
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of December 31, 2011	$ (283)	$ (342)	$ (625)

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 Statement of Income/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)
Regulatory Assets (a)	-	-	-
Regulatory Liabilities (a)	-	-	-
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 Statement of Income/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)
Regulatory Assets (a)	-	-	-
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of December 31, 2009	$ (138)	$ (463)	$ (601)

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

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's balance sheets at December 31, 2011 and 2010 were:

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2011

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ 91	$ -	$ 91
Hedging Liabilities (a)	521	-	521
AOCI Loss Net of Tax	(283)	(342)	(625)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(247)	(60)	(307)

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)

(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, 2011, 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 29 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. KPCo has not experienced 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, 2011 and 2010:

	December 31, 2011	December 31, 2010
	(in thousands)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 2,117	$ 1,368
Amount of Collateral KPCo Would Have Been Required to Post	1,314	2,614
Amount Attributable to RTO and ISO Activities	1,314	2,608

As of December 31, 2011 and 2010, KPCo was not required to post any collateral.

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 by Parent or the obligor under outstanding debt or a third party obligation 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, 2011 and 2010:

	December 31, 2011	December 31, 2010
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 16,265	$ 15,930
Amount of Cash Collateral Posted	1,715	1,376
Additional Settlement Liability if Cross Default Provision is Triggered	5,841	4,926

9. 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, 2011 and 2010 are summarized in the following table:

	December 31, 2011		December 31, 2010	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 549,055	$ 685,628	$ 548,888	$ 628,623

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, 2011 and 2010. 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, 2011

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (c)	$ 990	$ 63,922	$ 5,379	$ (54,018)	$ 16,273
Cash Flow Hedges:					
Commodity Hedges (a)	-	232	-	(141)	91
De-designated Risk Management Contracts (b)	-	-	-	324	324
Total Risk Management Assets	$ 990	$ 64,154	$ 5,379	$ (53,835)	$ 16,688
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (c)	$ 536	$ 61,607	$ 4,947	$ (59,248)	$ 7,842
Cash Flow Hedges:					
Commodity Hedges (a)	-	646	16	(141)	521
Total Risk Management Liabilities	$ 536	$ 62,253	$ 4,963	$ (59,389)	$ 8,363

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
De-designated 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

(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.

There have been no transfers between Level 1 and Level 2 during the years ended December 31, 2011 and 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, 2011	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of December 31, 2010	$ 1,073
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(454)
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	(16)
Purchases, Issuances and Settlements (c)	336
Transfers into Level 3 (d) (f)	524
Transfers out of Level 3 (e) (f)	(635)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(412)
Balance as of December 31, 2011	$ 416

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) (f)		232
Transfers out of Level 3 (e) (f)		(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 (h)		(103)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)		1,690
Balance as of December 31, 2009	$	1,899

(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) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(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) 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.

10. INCOME TAXES

The details of KPCo's income taxes as reported are as follows:

	Years Ended December 31,					
	2011		2010		2009	
			(in thousands)			
Income Tax Expense (Credit):						
Current	$	7,337	$	17,767	$	(40,140)
Deferred		17,766		1,075		50,612
Deferred Investment Tax Credits		(359)		(704)		(822)
Income Tax Expense	$	24,744	$	18,138	$	9,650

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,		
	2011	2010	2009
		(in thousands)	
Net Income	$ 42,374	$ 35,282	$ 23,936
Income Tax Expense	24,744	18,138	9,650
Pretax Income	$ 67,118	$ 53,420	$ 33,586
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 23,491	$ 18,697	$ 11,755
Increase (Decrease) in Income Taxes resulting from the following items:			
Depreciation	2,563	1,479	2,256
AFUDC	(818)	(720)	(626)
Removal Costs	(2,010)	(1,364)	(1,465)
Investment Tax Credits, Net	(359)	(704)	(822)
State and Local Income Taxes, Net	2,145	2,069	(2,938)
Other	(268)	(1,319)	1,490
Income Tax Expense	$ 24,744	$ 18,138	$ 9,650
Effective Income Tax Rate	36.9 %	34.0 %	28.7 %

The following table shows elements of KPCo's net deferred tax liability and significant temporary differences:

	December 31,	
	2011	2010
	(in thousands)	
Deferred Tax Assets	$ 34,383	$ 29,149
Deferred Tax Liabilities	(373,939)	(351,734)
Net Deferred Tax Liabilities	$ (339,556)	$ (322,585)
Property Related Temporary Differences	$ (262,078)	$ (239,361)
Amounts Due from Customers for Future Federal Income Taxes	(28,430)	(28,545)
Deferred State Income Taxes	(41,397)	(41,855)
Deferred Income Taxes on Other Comprehensive Loss	337	243
Accrued Pensions	8,771	9,285
Regulatory Assets	(25,686)	(23,129)
All Other, Net	8,927	777
Net Deferred Tax Liabilities	$ (339,556)	$ (322,585)

AEP System Tax Allocation Agreement

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.

Federal and State Income Tax Audit Status

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2009. KPCo and other AEP subsidiaries completed the examination of the years 2007 and 2008 in April 2011 and settled all outstanding issues on appeal for the years 2001 through 2006 in October 2011. The settlements did not have a material impact on KPCo and other AEP subsidiaries' net income, cash flows or financial condition. The IRS examination of years 2009 and 2010 started in October 2011. 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 effect on net income.

KPCo and other AEP subsidiaries file 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.

Net Income Tax Operating Loss Carryforward

In 2009, KPCo sustained federal, state and local net income tax operating losses 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 and realized the federal cash flow benefit 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, therefore the state and local losses were carried forward to future periods.

Tax Credit Carryforward

A federal income tax operating loss sustained in 2009 along with lower federal taxable income in 2011 and 2010 resulted in unused federal income tax credits of $1.1 million, not all of which have an expiration date. At December 31, 2011, KPCo had federal general business tax credit carryforwards of $133 thousand. If these credits are not utilized, the federal general business tax credits will expire in the years 2028 through 2031.

KPCo anticipates future federal taxable income will be sufficient to realize the tax benefits of the federal tax credits before they expire unused.

Uncertain Tax Positions

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

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

	Years Ended December 31,		
	2011	2010	2009
		(in thousands)	
Interest Expense	$ 193	$ 439	$ 1,113
Interest Income	1,849	-	-
Reversal of Prior Period Interest Expense	284	320	39

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

	December 31, 2011	December 31, 2010
	(in thousands)	
Accrual for Receipt of Interest	$ -	$ 475
Accrual for Payment of Interest and Penalties	2	566

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

	2011	2010	2009
		(in thousands)	
Balance at January 1,	$ 2,711	$ 2,553	$ 3,345
Increase - Tax Positions Taken During a Prior Period	1,604	970	2,178
Decrease - Tax Positions Taken During a Prior Period	(1,586)	(97)	(2,757)
Increase - Tax Positions Taken During the Current Year	-	-	-
Decrease - Tax Positions Taken During the Current Year	-	(202)	(141)
Increase - Settlements with Taxing Authorities	-	-	-
Decrease - Settlements with Taxing Authorities	(99)	(513)	-
Decrease - Lapse of the Applicable Statute of Limitations	(1,022)	-	(72)
Balance at December 31,	$ 1,608	$ 2,711	$ 2,553

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $(4) thousand, $184 thousand and $528 thousand for 2011, 2010 and 2009, 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 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.

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 did 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.

In December 2011, the U.S. Treasury Department issued guidance regarding the deduction and capitalization of expenditures related to tangible property. The guidance was in the form of proposed and temporary regulations and generally is effective for tax years beginning in 2012. These regulations did not have an impact on either net income or cash flow in 2011. Management is still evaluating the impact these regulations will have on future periods.

State Tax Legislation

In May 2011, Michigan repealed its Business Tax regime and replaced it with a traditional corporate net income tax with a rate of 6%, effective January 1, 2012.

During the third quarter of 2011, the state of West Virginia determined that the State had achieved certain minimum levels of shortfall reserve funds and thus, the West Virginia corporate income tax rate will be reduced to 7.75% in 2012. The enacted provisions will not have a material impact on KPCo's net income, cash flows or financial condition.

11. 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	**2011**	**2010**	**2009**
		(in thousands)	
Net Lease Expense on Operating Leases	$ 830	$ 836	$ 1,948
Amortization of Capital Leases	1,690	1,673	746
Interest on Capital Leases	311	304	53
Total Lease Rental Costs	$ 2,831	$ 2,813	$ 2,747

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,	
	2011	**2010**
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Generation	$ 683	$ 683
Other Property, Plant and Equipment	5,047	6,511
Total Property, Plant and Equipment Under Capital Leases	5,730	7,194
Accumulated Amortization	1,890	1,781
Net Property, Plant and Equipment Under Capital Leases	$ 3,840	$ 5,413
Obligations Under Capital Leases		
Noncurrent Liability	$ 2,387	$ 3,569
Liability Due Within One Year	1,453	1,844
Total Obligations Under Capital Leases	$ 3,840	$ 5,413

Future minimum lease payments consisted of the following at December 31, 2011:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2012	$ 1,624	$ 1,066
2013	1,438	1,029
2014	368	820
2015	314	687
2016	196	608
Later Years	309	950
Total Future Minimum Lease Payments	4,249	$ 5,160
Less Estimated Interest Element	409	
Estimated Present Value of Future Minimum Lease Payments	$ 3,840	

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 previously leased assets were not included in the 2010 refinancing, but were purchased or refinanced in 2011.

For equipment under the GE master lease agreements, the lessor is guaranteed receipt of up to 78% 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 78% 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, 2011, the maximum potential loss for these lease agreements was approximately $710 thousand 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.

12. 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, 2011 and 2010:

Type of Debt	Maturity	Weighted Average Interest rate at December 31, 2011	Interest Rate Ranges at December 31, 2011	Interest Rate Ranges at December 31, 2010	Outstanding at December 31, 2011	Outstanding at December 31, 2010
					(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					(945)	(1,112)
Total Long-term Debt Outstanding					549,055	548,888
Long-term Debt Due Within One Year					-	-
Long-term Debt					$ 549,055	$ 548,888

Long-term debt outstanding at December 31, 2011 is payable as follows:

	2012	2013	2014	2015	2016	After 2016	Total
				(in thousands)			
Principal Amount	$ -	$ -	$ -	$ 20,000	$ -	$ 530,000	$ 550,000
Unamortized Discount, Net							(945)
Total Long-term Debt Outstanding							$ 549,055

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 value of the common stock. This restriction does not limit the ability of KPCo to pay dividends out of retained earnings.

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 to the Utility Money Pool as of December 31, 2011 and 2010 is included in Advances to Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the years ended December 31, 2011 and 2010 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 to Utility Money Pool as of December 31,	Authorized Short-Term Borrowing Limit
			(in thousands)			
2011	$ -	$ 117,473	$ -	$ 89,182	$ 70,332	$ 250,000
2010	18,963	69,599	5,857	25,995	67,060	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, 2011, 2010 and 2009 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
2011	- %	- %	0.56 %	0.06 %	- %	0.35 %
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 %

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, 2011, 2010 and 2009:

	Years Ended December 31,		
	2011	**2010**	**2009**
		(in thousands)	
Interest Expense	$ -	$ 10	$ 983
Interest Income	318	49	18

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 2011, AEP Credit renewed its receivables securitization agreement. The agreement provides commitments of $750 million from bank conduits to finance receivables from AEP Credit with an increase to $800 million for the months of July, August and September to accommodate seasonal demand. A commitment of $375 million, with the seasonal increase to $425 million for the months of July, August and September, expires in June 2012 and the remaining commitment of $375 million expires in June 2014.

KPCo's amount of accounts receivable and accrued unbilled revenues sold under the sale of receivables agreement was $52 million and $63 million as of December 31, 2011 and 2010, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold were $2 million, $2 million and $2 million for the years ended December 31, 2011, 2010 and 2009, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit were $579 million, $548 million and $500 million as of December 31, 2011, 2010 and 2009, respectively.

13. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "AEP System Tax Allocation Agreement" section of Note 10 in addition to "Utility Money Pool – AEP System" and "Sale of Receivables – AEP Credit" sections of Note 12.

AEP Power Pool

APCo, I&M, KPCo, OPCo and AEPSC are parties to the Interconnection Agreement, which defines the sharing of costs and benefits associated with the respective generating plants. This sharing is based upon each AEP utility subsidiary's MLR and is calculated monthly on the basis of each AEP utility subsidiary's maximum peak demand in relation to the sum of the maximum peak demands of all four AEP utility subsidiaries during the preceding 12 months. In addition, APCo, I&M, KPCo and OPCo are 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.

Based upon the PUCO's January 2012 approval of OPCo's corporate separation plan, applications were filed in February 2012 with the FERC proposing to establish a new power cost sharing agreement between APCo, I&M and KPCo and transfer OPCo's generation assets to APCo, KPCo and a nonregulated AEP subsidiary. The Ohio corporate separation plan was subsequently rejected on rehearing in February 2012. Management is in the process of withdrawing the applications.

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, net transmission agreement sales, natural gas contracts with AEPES and other revenues for the years ended December 31, 2011, 2010 and 2009:

	Years Ended December 31,		
Related Party Revenues	**2011**	**2010**	**2009**
		(in thousands)	
Sales to AEP Power Pool	$ 67,170	$ 57,777	$ 64,074
Direct Sales to West Affiliates	314	711	454
Direct Sales to Transmission Companies	-	737	-
Transmission Agreement Sales	4,480	-	-
Natural Gas Contracts with AEPES	32	(435)	(1,823)
Other Revenues	263	1,215	(92)
Total Affiliated Revenues	$ 72,259	$ 60,005	$ 62,613

The following table shows the purchased power expense incurred from purchases from the pools and affiliates for the years ended December 31, 2011, 2010 and 2009:

	Years Ended December 31,		
Related Party Purchases	**2011**	**2010**	**2009**
		(in thousands)	
Purchases from AEP Power Pool	$ 115,583	$ 107,199	$ 96,284
Direct Purchases from West Affiliates	51	169	305
Purchases from AEGCo	98,031	101,032	101,731
Total Purchases	$ 213,665	$ 208,400	$ 198,320

The above summarized related party revenues and expenses are reported in 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.
- 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, 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 charge recorded as a result of the new TA for the year ended December 31, 2011 was $410 thousand and was recorded in Other Operation expense on KPCo's statement of income.

KPCo's net credits as allocated under the original TA for the years ended December 31, 2010 and 2009 were $8 million and $9 million, respectively, and were recorded in Other Operation expense on KPCo's statements of income.

PSO, SWEPCo and AEPSC are parties to the TCA, dated January 1, 1997, revised 1999 and 2011, as restated and amended, by and among PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two AEP utility subsidiaries. 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 parties to the agreement.

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 $183 thousand, $195 thousand and $88 thousand for the years ended December 31, 2011, 2010 and 2009, 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 $122 thousand, $133 thousand and $112 thousand in 2011, 2010 and 2009, 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 the cost of performing these services on the balance sheet, 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 $298 thousand, $368 thousand and $358 thousand for the years ended December 31, 2011, 2010 and 2009, 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 the statements of income. KPCo's realized and unrealized losses recorded for the years ended December 31, 2010 and 2009 were $837 thousand and $340 thousand, respectively.

Affiliate Railcar Agreement

KPCo has an agreement providing for the use of its 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 the 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	**2011**	**2010**
	(in thousands)	
APCo	$ 289	$ 399
OPCo	355	245

AEP Power Pool Purchases from OVEC

In 2011, the AEP Power Pool purchased power from OVEC to serve off-system sales and retail sales. These purchases are reported in Purchased Electricity for Resale on KPCo's statement of income. KPCo recorded $4.5 million in expense for the year ended December 31, 2011.

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 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 – Transmission Companies

In 2009, AEP Transmission Company, LLC (AEP Transco) formed seven wholly-owned transmission companies. AEP Transco is the holding company for the seven transmission companies. These seven companies consist of: AEP Appalachian Transmission Company, Inc., AEP Indiana Michigan Transmission Company, Inc., AEP Kentucky Transmission Company, Inc. (KTCo), AEP Ohio Transmission Company, Inc., AEP West Virginia Transmission Company, Inc., AEP Oklahoma Transmission Company, Inc. and AEP Southwestern Transmission Company, Inc.

KTCo sold transmission property to KPCo during 2011 for $1.2 million, which was recorded at net book value in Property, Plant and Equipment on the balance sheet. There were no gains or losses recorded on the transactions.

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, 2011, 2010 and 2009 as shown in the following table:

	Years Ended December 31,		
Companies	**2011**	**2010**	**2009**
		(in thousands)	
APCo to KPCo	$ 555	$ 209	$ -
OPCo to KPCo	-	960	-

In addition, KPCo had aggregate affiliated sales and purchases of meters and transformers for the years ended December 31, 2011, 2010 and 2009 as shown in the following table:

	APCo	**I&M**	**KGPCo**	**OPCo**	**PSO**	**SWEPCo**	**TCC**	**TNC**	**WPCo**	**Total**
Sales						(in thousands)				
2011	$ 289	$ 10	$ 1	$ 91	$ -	$ 8	$ 2	$ 3	$ -	$ 404
2010	364	6	23	92	-	2	-	-	-	487
2009	505	64	7	156	3	8	-	-	1	744
Purchases										
2011	119	-	3	44	-	-	240	12	7	425
2010	139	7	-	139	-	3	-	-	-	288
2009	161	50	-	87	-	26	-	-	-	324

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

Global Borrowing Notes

As of December 31, 2011 and 2010, 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.

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.

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, the power to direct the VIE, variable interests held by related parties 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 AEP's subsidiaries. AEP is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP 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 any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do 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. KPCo's total billings from AEPSC for the years ended December 31, 2011, 2010 and 2009 were $32 million, $37 million and $34 million, respectively. The carrying amount of liabilities associated with AEPSC for the years ended December 31, 2011 and 2010 was $3 million and $3 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, 2011, 2010 and 2009 were $98 million, $101 million and $102 million, respectively. The carrying amount of liabilities associated with AEGCo for the years ended December 31, 2011 and 2010 was $9 million and $10 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

14. 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:

2011	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	$ 554,218	$ 211,512	3.8%	40-50	$ -	$ -	-	-
Transmission	456,552	154,680	1.7%	25-75	-	-	-	-
Distribution	612,832	186,679	3.5%	11-75	-	-	-	-
CWIP	71,290	(1,948)	NM	NM	-	-	-	-
Other	54,690	22,747	8.2%	NM	5,700	201	NM	NM
Total	$ 1,749,582	$ 573,670			$ 5,700	$ 201		

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)	NM	NM	-	-	-	-
Other	58,282	23,371	8.3%	NM	5,700	195	NM	NM
Total	$ 1,680,873	$ 542,248			$ 5,700	$ 195		

2009	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	3.8%	40-50	-	-
Transmission	1.7%	25-75	-	-
Distribution	3.4%	11-75	-	-
CWIP	NM	NM	-	-
Other	9.7%	NM	NM	NM

NM 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 2011 and 2010 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)			
2011	$ 4,186	$ 346	$ -	$ (295)	$ (465)	$ 3,772
2010	3,506	292	823	(435)	-	4,186

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, 2011	2010	2009
		(in thousands)	
Allowance for Equity Funds Used During Construction	$ 1,229	$ 768	$ 391
Allowance for Borrowed Funds Used During Construction	900	594	394

15. 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 was eliminated across the AEP System as a result of process improvements, streamlined organizational designs and other efficiencies. Most of the affected employees terminated employment May 31, 2010. The severance program provided two weeks of base pay for every year of service along with other severance benefits.

KPCo recorded a charge to Other Operation expense during 2010 primarily related to severance benefits as the result of headcount reduction initiatives. The total amount incurred in 2010 by KPCo was $11.7 million.

KPCo's cost reduction activity for the year ended December 31, 2011 is described in the following table:

Balance at December 31, 2010	Incurred	Settled	Adjustments	Balance at December 31, 2011
		(in thousands)		
$ 1,018	$ -	$ (449)	$ (569)	$ -

16. 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:

	2011 Quarterly Periods Ended			
	March 31	**June 30**	**September 30**	**December 31**
	(in thousands)			
Total Revenues	$ 196,118	$ 174,674	$ 186,444	$ 171,708
Operating Income	35,277	14,562	25,863	24,274
Net Income	16,870	3,472	11,853	10,179

	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)

(a) See Note 15 for discussion of expenses related to cost reduction initiatives recorded in the second quarter of 2010.
(b) New base rates became effective in third quarter of 2010.

There were no significant events in 2011.