Kentucky Power Company

2009 First Quarter Report

Financial Statements

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GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEP System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
ALJ	Administrative Law Judge.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
CAA	Clean Air Act.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW Operating Agreement	Agreement, dated January 1, 1997, by and among PSO, SWEPCo, TCC and TNC governing generating capacity allocation. This agreement was amended in May 2006 to remove TCC and TNC. AEPSC acts as the agent.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
EITF 06-10	EITF Issue No. 06-10 "Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements."
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN	FASB Interpretation No.
FIN 46R	FIN 46R, "Consolidation of Variable Interest Entities."
FSP	FASB Staff Position.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
OCC	Corporation Commission of the State of Oklahoma.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCT	Public Utility Commission of Texas.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
RTO	Regional Transmission Organization.
SECA	Seams Elimination Cost Allocation.

Term	Meaning
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 133	Statement of Financial Accounting Standards No. 133, “Accounting for Derivative Instruments and Hedging Activities.”
SFAS 157	Statement of Financial Accounting Standards No. 157, “Fair Value Measurements.”
SIA	System Integration Agreement.
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.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2009 and 2008
(in thousands)
(Unaudited)

	2009	2008
REVENUES		
Electric Generation, Transmission and Distribution	$ 161,249	$ 147,059
Sales to AEP Affiliates	15,423	20,053
Other	1,761	178
TOTAL	178,433	167,290
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	53,041	49,211
Purchased Electricity for Resale	8,617	3,766
Purchased Electricity from AEP Affiliates	48,186	54,190
Other Operation	12,038	15,508
Maintenance	21,345	9,920
Depreciation and Amortization	12,807	11,958
Taxes Other Than Income Taxes	2,346	1,180
TOTAL	158,380	145,733
OPERATING INCOME	20,053	21,557
Other Income (Expense):		
Interest Income	50	1,288
Allowance for Equity Funds Used During Construction	(22)	344
Interest Expense	(7,310)	(6,855)
INCOME BEFORE INCOME TAX EXPENSE	12,771	16,334
Income Tax Expense	3,317	5,190
NET INCOME	$ 9,454	$ 11,144

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

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2009 and 2008
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2007	$ 50,450	$ 208,750	$ 128,583	$ (814)	$ 386,969
EITF 06-10 Adoption, Net of Tax of $197			(365)		(365)
Common Stock Dividends			(2,500)		(2,500)
TOTAL					384,104
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,258				(2,335)	(2,335)
NET INCOME			11,144		11,144
TOTAL COMPREHENSIVE INCOME					8,809
MARCH 31, 2008	$ 50,450	$ 208,750	$ 136,862	$ (3,149)	$ 392,913
DECEMBER 31, 2008	$ 50,450	$ 208,750	$ 138,749	$ 59	$ 398,008
Common Stock Dividends			(6,750)		(6,750)
TOTAL					391,258
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $134				249	249
NET INCOME			9,454		9,454
TOTAL COMPREHENSIVE INCOME					9,703
MARCH 31, 2009	$ 50,450	$ 208,750	$ 141,453	$ 308	$ 400,961

See Condensed Notes to Condensed Financial Statements.

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

	2009	2008
CURRENT ASSETS		
Cash and Cash Equivalents	$ 676	$ 646
Accounts Receivable:		
Customers	17,976	24,214
Affiliated Companies	7,440	6,721
Miscellaneous	133	83
Allowance for Uncollectible Accounts	(1,158)	(1,144)
Total Accounts Receivable	24,391	29,874
Fuel	27,154	29,440
Materials and Supplies	10,763	10,630
Risk Management Assets	14,658	13,760
Accrued Tax Benefits	6,689	41
Regulatory Asset for Under-Recovered Fuel Costs	9,940	9,953
Margin Deposits	7,917	5,207
Prepayments and Other	2,591	5,710
TOTAL	104,779	105,261
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	539,736	533,998
Transmission	434,353	431,835
Distribution	541,428	528,711
Other	63,683	65,485
Construction Work in Progress	35,580	46,650
Total	1,614,780	1,606,679
Accumulated Depreciation and Amortization	487,768	476,568
TOTAL - NET	1,127,012	1,130,111
OTHER NONCURRENT ASSETS		
Regulatory Assets	180,364	179,845
Long-term Risk Management Assets	12,967	10,860
Deferred Charges and Other	38,776	41,884
TOTAL	232,107	232,589
TOTAL ASSETS	$ 1,463,898	$ 1,467,961

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
March 31, 2009 and December 31, 2008
(Unaudited)

	2009	2008
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 157,290	$ 131,399
Accounts Payable:		
General	45,980	35,584
Affiliated Companies	14,776	45,245
Risk Management Liabilities	7,640	6,316
Customer Deposits	16,875	15,985
Accrued Taxes	8,486	11,903
Other	21,520	29,526
TOTAL	272,567	275,958
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	398,597	398,555
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	6,024	5,630
Deferred Income Taxes	264,648	259,666
Regulatory Liabilities and Deferred Investment Tax Credits	37,526	46,135
Deferred Credits and Other	63,575	64,009
TOTAL	790,370	793,995
TOTAL LIABILITIES	1,062,937	1,069,953
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	208,750	208,750
Retained Earnings	141,453	138,749
Accumulated Other Comprehensive Income (Loss)	308	59
TOTAL	400,961	398,008
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 1,463,898	$ 1,467,961

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2009 and 2008
(in thousands)
(Unaudited)

	2009	2008
OPERATING ACTIVITIES		
Net Income	$ 9,454	$ 11,144
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	12,807	11,958
Deferred Income Taxes	10,516	(979)
Allowance for Equity Funds Used During Construction	22	(344)
Mark-to-Market of Risk Management Contracts	(906)	(749)
Change in Other Noncurrent Assets	2,883	(888)
Change in Other Noncurrent Liabilities	(1,268)	246
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	5,483	3,292
Fuel, Materials and Supplies	2,153	(5,663)
Accounts Payable	(16,213)	(5,119)
Customer Deposits	890	532
Accrued Taxes, Net	(10,065)	811
Other Current Assets	(3,329)	2,748
Other Current Liabilities	(11,660)	(7,618)
Net Cash Flows from Operating Activities	767	9,371
INVESTING ACTIVITIES		
Construction Expenditures	(19,859)	(27,784)
Proceeds from Sales of Assets	161	129
Net Cash Flows Used for Investing Activities	(19,698)	(27,655)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	25,891	21,152
Principal Payments for Capital Lease Obligations	(180)	(206)
Dividends Paid on Common Stock	(6,750)	(2,500)
Net Cash Flows from Financing Activities	18,961	18,446
Net Increase in Cash and Cash Equivalents	30	162
Cash and Cash Equivalents at Beginning of Period	646	727
Cash and Cash Equivalents at End of Period	$ 676	$ 889
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 17,080	$ 10,934
Net Cash Paid (Received) for Income Taxes	336	(354)
Noncash Acquisitions Under Capital Leases	49	84
Construction Expenditures Included in Accounts Payable at March 31,	5,802	6,846

See Condensed Notes to Condensed Financial Statements.

CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. Significant Accounting Matters
2. New Accounting Pronouncements
3. Rate Matters
4. Commitments, Guarantees and Contingencies
5. Benefit Plans
6. Business Segments
7. Derivatives, Hedging and Fair Value Measurements
8. Income Taxes
9. Financing Activities

1. SIGNIFICANT ACCOUNTING MATTERS

General

The accompanying unaudited condensed financial statements and footnotes were prepared in accordance with GAAP for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods. The net income for the three months ended March 31, 2009 are not necessarily indicative of results that may be expected for the year ending December 31, 2009. The accompanying condensed financial statements are unaudited and should be read in conjunction with the audited 2008 financial statements and notes thereto, which are included in KPCo's 2008 Annual Report.

Variable Interest Entities

FIN 46R is a consolidation model that considers risk absorption of a variable interest entity (VIE), also referred to as variability. Entities are required to consolidate a VIE when it is determined that they are the primary beneficiary of that VIE, as defined by FIN 46R. In determining whether KPCo is the primary beneficiary of a VIE, management considers factors such as equity at risk, the amount of the VIE's variability KPCo absorbs, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE and other factors. Management believes that the significant assumptions and judgments were applied consistently and that there are no other reasonable judgments or assumptions that would result in a different conclusion. There have been no changes to the reporting of VIEs in the financial statements where it is concluded that KPCo is the primary beneficiary. In addition, KPCo has not provided financial or other support to any VIE that was not previously contractually required.

KPCo holds a significant variable interest in AEPSC and AEGCo. AEPSC provides certain managerial and professional services to KPCo. AEP is the sole equity owner of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to KPCo at AEPSC's cost. KPCo has not provided financial or other support outside the reimbursement of costs for services rendered. The cost reimbursement nature of AEPSC finances its operations. There are no other terms or arrangements between AEPSC and KPCo that could require additional financial support from KPCo or expose it to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. KPCo is exposed to losses to the extent it cannot recover the costs of AEPSC through its normal business operations. KPCo is considered to have a significant interest in the variability of AEPSC due to its activity in AEPSC's cost reimbursement structure. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. Total billings from AEPSC for the three months ended March 31, 2009 and 2008 were $8 million and $10 million, respectively. The carrying amount of liabilities associated with AEPSC for the three months ended March 31, 2009 and for the year ended December 31, 2008 were $2 million and $5 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant Unit 1, leases a 50% interest in Rockport Plant Unit 2 and owns 100% of the Lawrenceburg Generating Station. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. KPCo has no involvement with AEGCo's interest in the Lawrenceburg Generating Station. AEP guarantees all the debt obligations of AEGCo. KPCo is considered to have a significant interest in AEGCo due to its transactions. KPCo is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. Due to the nature of the AEP Power Pool, there is a sharing of the cost of Rockport Plant such that no member of the AEP Power Pool is the primary beneficiary of AEGCo's Rockport Plant. In the event AEGCo would require financing or other support outside the billings to KPCo, this financing would be provided by AEP. Total billings from AEGCo for the three months ended March 31, 2009 and 2008 were $27 million and $25 million, respectively. The carrying amount of liabilities associated with AEGCo for the three months ended March 31, 2009 and for the year ended December 31, 2008 were $8 million and $9 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

Revenue Recognition – Traditional Electricity Supply and Demand

Revenues are recognized from retail and wholesale electricity sales and electricity transmission and distribution delivery services. KPCo recognizes the revenues on its Condensed Consolidated 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 then purchase power from PJM to supply their customers. Generally, these power sales and purchases are reported on a net basis as revenues on KPCo's Condensed Statements of Income. However, in the first quarter of 2009, there were times when the AEP East companies were purchasers of power from PJM to serve retail load. These purchases were recorded gross as Purchased Electricity for Resale on KPCo's Condensed Statements of Income.

Physical energy purchases, including those from RTOs, that are identified as non-trading, are accounted for on a gross basis in Purchased Electricity for Resale on KPCo's Condensed Statements of Income.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management reviews the new accounting literature to determine the relevance, if any, to KPCo's business. The following represents a summary of new pronouncements issued or implemented in 2009 and standards issued but not implemented that management has determined relate to KPCo's operations.

Pronouncements Adopted During the First Quarter of 2009

The following standards were effective during the first quarter of 2009. Consequently, the financial statements and footnotes reflect their impact.

SFAS 141 (revised 2007) "Business Combinations" (SFAS 141R)

In December 2007, the FASB issued SFAS 141R, improving financial reporting about business combinations and their effects. It established how the acquiring entity recognizes and measures the identifiable assets acquired, liabilities assumed, goodwill acquired, any gain on bargain purchases and any noncontrolling interest in the acquired entity. SFAS 141R no longer allows acquisition-related costs to be included in the cost of the business combination, but rather expensed in the periods they are incurred, with the exception of the costs to issue debt or equity securities which shall be recognized in accordance with other applicable GAAP. The standard requires disclosure of information for a business combination that occurs during the accounting period or prior to the issuance of the financial statements for the accounting period. SFAS 141R can affect tax positions on previous acquisitions. KPCo does not have any such tax positions that result in adjustments.

In April 2009, the FASB issued FSP SFAS 141(R)-1 "Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies." The standard clarifies accounting and disclosure for contingencies arising in business combinations. It was effective January 1, 2009.

KPCo adopted SFAS 141R, including the FSP, effective January 1, 2009. It is effective prospectively for business combinations with an acquisition date on or after January 1, 2009. KPCo will apply it to any future business combinations.

SFAS 160 "Noncontrolling Interest in Consolidated Financial Statements" (SFAS 160)

In December 2007, the FASB issued SFAS 160, modifying reporting for noncontrolling interest (minority interest) in consolidated financial statements. It requires noncontrolling interest be reported in equity and establishes a new framework for recognizing net income or loss and comprehensive income by the controlling interest. Upon deconsolidation due to loss of control over a subsidiary, the standard requires a fair value remeasurement of any remaining noncontrolling equity investment to be used to properly recognize the gain or loss. SFAS 160 requires specific disclosures regarding changes in equity interest of both the controlling and noncontrolling parties and presentation of the noncontrolling equity balance and income or loss for all periods presented.

KPCo adopted SFAS 160 effective January 1, 2009 with no impact on its financial statements or footnote disclosures.

SFAS 161 “Disclosures about Derivative Instruments and Hedging Activities” (SFAS 161)

In March 2008, the FASB issued SFAS 161, enhancing disclosure requirements for derivative instruments and hedging activities. Affected entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how an entity accounts for derivative instruments and related hedged items and (c) how derivative instruments and related hedged items affect an entity’s financial position, financial performance and cash flows. The standard requires that objectives for using derivative instruments be disclosed in terms of the primary underlying risk and accounting designation.

KPCo adopted SFAS 161 effective January 1, 2009. This standard increased disclosures related to derivative instruments and hedging activities. See “Derivatives and Hedging ” section of Note 7 for further information.

EITF Issue No. 08-5 “Issuer’s Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement” (EITF 08-5)

In September 2008, the FASB ratified the consensus on liabilities with third-party credit enhancements when the liability is measured and disclosed at fair value. The consensus treats the liability and the credit enhancement as two units of accounting. Under the consensus, the fair value measurement of the liability does not include the effect of the third-party credit enhancement. Consequently, changes in the issuer’s credit standing without the support of the credit enhancement affect the fair value measurement of the issuer’s liability. Entities will need to provide disclosures about the existence of any third-party credit enhancements related to their liabilities. In the period of adoption, entities must disclose the valuation method(s) used to measure the fair value of liabilities within its scope and any change in the fair value measurement method that occurs as a result of its initial application.

KPCo adopted EITF 08-5 effective January 1, 2009. It will be applied prospectively with the effect of initial application included as a change in fair value of the liability.

EITF Issue No. 08-6 “Equity Method Investment Accounting Considerations” (EITF 08-6)

In November 2008, the FASB ratified the consensus on equity method investment accounting including initial and allocated carrying values and subsequent measurements. It requires initial carrying value be determined using the SFAS 141R cost allocation method. When an investee issues shares, the equity method investor should treat the transaction as if the investor sold part of its interest.

KPCo adopted EITF 08-6 effective January 1, 2009 with no impact on the financial statements. It was applied prospectively.

FSP SFAS 142-3 “Determination of the Useful Life of Intangible Assets” (SFAS 142-3)

In April 2008, the FASB issued SFAS 142-3 amending factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. The standard is expected to improve consistency between the useful life of a recognized intangible asset and the period of expected cash flows used to measure its fair value.

KPCo adopted SFAS 142-3 effective January 1, 2009. The guidance is prospectively applied to intangible assets acquired after the effective date. The standard’s disclosure requirements are applied prospectively to all intangible assets as of January 1, 2009. The adoption of this standard had no impact on the financial statements.

FSP SFAS 157-2 “Effective Date of FASB Statement No. 157” (SFAS 157-2)

In February 2008, the FASB issued SFAS 157-2 which delays the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). As defined in SFAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities and the lowest priority to unobservable inputs. 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.

KPCo adopted SFAS 157-2 effective January 1, 2009. KPCo will apply these requirements to applicable fair value measurements which include new asset retirement obligations and impairment analysis related to long-lived assets, equity investments, goodwill and intangibles. KPCo did not record any fair value measurements for nonrecurring nonfinancial assets and liabilities in the first quarter of 2009.

Pronouncements Effective in the Future

The following standards will be effective in the future and their impacts disclosed at that time.

FSP SFAS 107-1 and APB 28-1 "Interim Disclosures about Fair Value of Financial Instruments" (FSP SFAS 107-1 and APB 28-1)

In April 2009, the FASB issued FSP SFAS 107-1 and APB 28-1 requiring disclosure about the fair value of financial instruments in all interim reporting periods. The standard requires disclosure of the method and significant assumptions used to determine the fair value of financial instruments.

This standard is effective for interim periods ending after June 15, 2009. Management expects this standard to increase the disclosure requirements related to financial instruments. KPCo will adopt the standard effective second quarter of 2009.

FSP SFAS 115-2 and SFAS 124-2 "Recognition and Presentation of Other-Than-Temporary Impairments" (FSP SFAS 115-2 and SFAS 124-2)

In April 2009, the FASB issued FSP SFAS 115-2 and SFAS 124-2 amending the other-than-temporary impairment (OTTI) recognition and measurement guidance for debt securities. For both debt and equity securities, the standard requires disclosure for each interim reporting period of information by security class similar to previous annual disclosure requirements.

This standard is effective for interim periods ending after June 15, 2009. Management does not expect a material impact as a result of the new OTTI evaluation method for debt securities, but expects this standard to increase the disclosure requirements related to financial instruments. KPCo will adopt the standard effective second quarter of 2009.

FSP SFAS 132R-1 "Employers' Disclosures about Postretirement Benefit Plan Assets" (FSP SFAS 132R-1)

In December 2008, the FASB issued FSP SFAS 132R-1 providing additional disclosure guidance for pension and OPEB plan assets. The rule requires disclosure of investment policy including target allocations by investment class, investment goals, risk management policies and permitted or prohibited investments. It specifies a minimum of investment classes by further dividing equity and debt securities by issuer grouping. The standard adds disclosure requirements including hierarchical classes for fair value and concentration of risk.

This standard is effective for fiscal years ending after December 15, 2009. Management expects this standard to increase the disclosure requirements related to AEP's benefit plans. KPCo will adopt the standard effective for the 2009 Annual Report.

FSP SFAS 157-4 "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly" (FSP SFAS 157-4)

In April 2009, the FASB issued FSP SFAS 157-4 providing additional guidance on estimating fair value when the volume and level of activity for an asset or liability has significantly decreased, including guidance on identifying circumstances indicating when a transaction is not orderly. Fair value measurements shall be based on the price that would be received to sell an asset or paid to transfer a liability in an orderly (not a distressed sale or forced liquidation) transaction between market participants at the measurement date under current market conditions. The standard also requires disclosures of the inputs and valuation techniques used to measure fair value and a discussion of changes in valuation techniques and related inputs, if any, for both interim and annual periods.

This standard is effective for interim and annual periods ending after June 15, 2009. Management expects this standard to have no impact on the financial statement but will increase disclosure requirements. KPCo will adopt the standard effective second quarter of 2009.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by the FASB, management cannot determine the impact on the reporting of operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, contingencies, liabilities and equity, emission allowances, leases, insurance, hedge accounting, discontinued operations, trading inventory and related tax impacts. Management also expects to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on future net income and financial position.

3. RATE MATTERS

As discussed in KPCo's 2008 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo's 2008 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2009 and updates KPCo's 2008 Annual Report.

Validity of Nonstatutory Surcharges

In August 2007, the Franklin County Circuit Court concluded the KPSC did not have the authority to order a surcharge for a gas company subsidiary of Duke Energy absent a full cost of service rate proceeding due to the lack of statutory authority. The Kentucky Attorney General (AG) notified the KPSC that the Franklin County Circuit Court judge's order in the Duke Energy case can be interpreted to include other existing surcharges, rates or fees established outside of the context of a general rate case proceeding and not specifically authorized by statute, including fuel clauses. Both the KPSC and Duke Energy appealed the Franklin County Circuit Court decision.

Although this order is not directly applicable, KPCo has existing surcharges which are not specifically authorized by statute. These include KPCo's fuel clause surcharge, the annual Rockport Plant capacity surcharge, the merger surcredit and the off-system sales credit rider. On an annual basis, these surcharges recently ranged from revenues of approximately $10 million to a reduction of revenues of $2 million due to the volatility of these surcharges. The KPSC asked interested parties to brief the issue in KPCo's fuel cost proceeding. The AG responded that the KPCo fuel clause should be invalidated because the KPSC lacked the authority to implement a fuel clause for KPCo without a full rate case review. The KPSC issued an order stating that it has the authority to provide for surcharges and surcredits until the court of appeals rules otherwise.

In November 2008, the Kentucky Court of Appeals concluded that Duke Energy's surcharge was illegal. However, the order stated that the "decision was premised on the nature of the long-term capital improvements proposed by Duke Energy as distinguished from the fuel increases that are fluctuating and unanticipated. The latter have been approved by the Kentucky Supreme Court and remain the law." In February 2009, the Kentucky Court of Appeals denied the KPSC request for appeal of the Franklin County Circuit Court decision. In March 2009, the KPSC filed for a discretionary review of the related Duke Energy case with the Kentucky Supreme Court. Management believes that all of KPCo's variable rate mechanisms are valid and would be upheld if ever challenged.

FERC Rate Matters

Regional Transmission Rate Proceedings at the FERC

SECA Revenue Subject to Refund

Effective December 1, 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected, at the FERC's direction, load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 31, 2006. Intervenors objected to the temporary SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than they collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues of $220 million from December 2004 through March 2006 when the SECA rates terminated leaving the AEP East companies and ultimately their internal load retail customers to make up the short fall in revenues. KPCo's portion of recognized gross SECA revenues was $17 million.

In August 2006, a FERC ALJ issued an initial decision, finding that the rate design for the recovery of SECA charges was flawed and that a large portion of the "lost revenues" reflected in the SECA rates should not have been recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made. The ALJ also found that the unpaid SECA rates must be paid in the recommended reduced amount.

In September 2006, AEP filed briefs jointly with other affected companies noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision in large part. Management believes, based on advice of legal counsel, that the FERC should reject the ALJ's initial decision because it contradicts prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ's findings on key issues are largely without merit. AEP and SECA ratepayers are engaged in settlement discussions in an effort to settle the SECA issue. However, if the ALJ's initial decision is upheld in its entirety, it could result in a disallowance of a large portion of any unsettled SECA revenues.

Based on anticipated settlements, the AEP East companies provided reserves for net refunds for current and future SECA settlements totaling $39 million and $5 million in 2006 and 2007, respectively, applicable to a total of $220 million of SECA revenues. KPCo provided reserves of $2.9 million and $400 thousand in 2006 and 2007, respectively.

In February 2009, a settlement agreement was approved by the FERC resulting in the completion of a $1 million settlement applicable to $20 million of SECA revenue. Including this most recent settlement, AEP has completed settlements totaling $10 million applicable to $112 million of SECA revenues. The balance in the reserve for future settlements as of March 2009 was $34 million. KPCo's reserve balance at March 31, 2009 was $2.6 million. As of March 31, 2009, there were no in-process settlements.

If the FERC adopts the ALJ's decision and/or AEP cannot settle all of the remaining unsettled claims within the remaining amount reserved for refund, it will have an adverse effect on future net income and cash flows. Based on advice of external FERC counsel, recent settlement experience and the expectation that most of the unsettled SECA revenues will be settled, management believes that the available reserve of $34 million is adequate to settle the remaining $108 million of contested SECA revenues. If the remaining unsettled SECA claims are settled for considerably more than the to-date settlements or if the remaining unsettled claims are awarded a refund by the FERC greater than the remaining reserve balance, it could have an adverse effect on net income. Cash flows will be adversely impacted by any additional settlements or ordered refunds. However, management cannot predict the ultimate outcome of ongoing settlement discussions or future FERC proceedings or court appeals, if any.

<u>The FERC PJM Regional Transmission Rate Proceeding</u>

With the elimination of T&O rates, the expiration of SECA rates and after considerable administrative litigation at the FERC in which AEP sought to mitigate the effect of the T&O rate elimination, the FERC failed to implement a regional rate in PJM. As a result, the AEP East companies' retail customers incur the bulk of the cost of the existing AEP east transmission zone facilities. However, the FERC ruled that the cost of any new 500 kV and higher voltage transmission facilities built in PJM would be shared by all customers in the region. It is expected that most of the new 500 kV and higher voltage transmission facilities will be built in other zones of PJM, not AEP's zone. The AEP East companies will need to obtain state regulatory approvals for recovery of any costs of new facilities that are assigned to them by PJM. In February 2008, AEP filed a Petition for Review of the FERC orders in this case in the United States Court of Appeals. Management cannot estimate at this time what effect, if any, this order will have on the AEP East companies' future construction of new transmission facilities, net income and cash flows.

The AEP East companies filed for and in 2006 obtained increases in their wholesale transmission rates to recover lost revenues previously applied to reduce those rates. AEP has also sought and received retail rate increases in Ohio, Virginia, West Virginia and Kentucky. In January and March 2009, AEP received retail rate increases in Tennessee and Indiana, respectively, that recognized the higher retail transmission costs resulting from the loss of wholesale transmission revenues from T&O transactions. As a result, AEP is now recovering approximately 98% of the lost T&O transmission revenues. The remaining 2% is being incurred by I&M until it can revise its rates in Michigan to recover the lost revenues.

<u>The FERC PJM and MISO Regional Transmission Rate Proceeding</u>

In the SECA proceedings, the FERC ordered the RTOs and transmission owners in the PJM/MISO region (the Super Region) to file, by August 1, 2007, a proposal to establish a permanent transmission rate design for the Super Region to be effective February 1, 2008. All of the transmission owners in PJM and MISO, with the exception of AEP and one MISO transmission owner, elected to support continuation of zonal rates in both RTOs. In September 2007, AEP filed a formal complaint proposing a highway/byway rate design be implemented for the Super Region where users pay based on their use of the transmission system. AEP argued the use of other PJM and MISO facilities by AEP is not as large as the use of AEP transmission by others in PJM and MISO. Therefore, a regional rate design change is required to recognize that the provision and use of transmission service in the Super Region is not sufficiently uniform between transmission owners and users to justify zonal rates. In January 2008, the FERC denied AEP's complaint. AEP filed a rehearing request with the FERC in March 2008. In December 2008, the FERC denied AEP's request for rehearing. In February 2009, AEP filed an appeal in the U.S. Court of Appeals. If the court appeal is successful, earnings could benefit for a certain period of time due to regulatory lag until the AEP East companies reduce future retail revenues in their next fuel or base rate proceedings to reflect the resultant additional transmission cost reductions. Management is unable to predict the outcome of this case.

PJM Transmission Formula Rate Filing

In July 2008, AEP filed an application with the FERC to increase its rates for wholesale transmission service within PJM by $63 million annually. The filing seeks to implement a formula rate allowing annual adjustments reflecting future changes in the AEP East companies' cost of service. In September 2008, the FERC issued an order conditionally accepting AEP's proposed formula rate, subject to a compliance filing, established a settlement proceeding with an ALJ, and delayed the requested October 2008 effective date for five months. The requested increase, which the AEP East companies began billing in April 2009 for service as of March 1, 2009, will produce a $63 million annualized increase in revenues. Approximately $8 million of the increase will be collected from nonaffiliated customers within PJM. The remaining $55 million requested would be billed to the AEP East companies but would be offset by compensation from PJM for use of the AEP East companies' transmission facilities so that retail rates for jurisdictions other than Ohio are not directly affected. In October 2008, AEP filed the required compliance filing, and began settlement discussions with the intervenors and FERC staff. The settlement discussions are currently ongoing. Under the formula, rates will be updated effective July 1, 2009, and each year thereafter. Also, beginning with the July 1, 2010 update, the rates each year will include an adjustment to true-up the prior year's collections to the actual costs for the prior year. Management is unable to predict the outcome of the settlement discussions or any further proceedings that might be necessary if settlement discussions are not successful.

Allocation of Off-system Sales Margins

In August 2008, the OCC filed a complaint at the FERC alleging that AEP inappropriately allocated off-system sales margins between the AEP East companies and the AEP West companies and did not properly allocate off-system sales margins within the AEP West companies. The PUCT, the APSC and the Oklahoma Industrial Energy Consumers intervened in this filing. In November 2008, the FERC issued a final order concluding that AEP inappropriately deviated from off-system sales margin allocation methods in the SIA and the CSW Operating Agreement for the period June 2000 through March 2006. The FERC ordered AEP to recalculate and reallocate the off-system sales margins in compliance with the SIA and to have the AEP East companies issue refunds to the AEP West companies. Although the FERC determined that AEP deviated from the CSW Operating Agreement, the FERC determined the allocation methodology was reasonable. The FERC ordered AEP to submit a revised CSW Operating Agreement for the period June 2000 to March 2006. In December 2008, AEP filed a motion for rehearing and a revised CSW Operating Agreement for the period June 2000 to March 2006. The motion for rehearing is still pending. In January 2009, AEP filed a compliance filing with the FERC and refunded approximately $250 million from the AEP East companies to the AEP West companies. The AEP West companies shared a portion of such revenues with their wholesale and retail customers during the period June 2000 to March 2006. In December 2008, the AEP West companies recorded a provision for refund. Management cannot predict the outcome of the requested FERC rehearing proceeding or any future state regulatory proceedings but believes the AEP West companies' provision for refund regarding future regulatory proceedings is adequate.

Transmission Equalization Agreement (TEA)

Certain transmission equipment placed in service in 1998 in KPCo's service territory was inadvertently excluded from the AEP East companies' TEA calculation. As a result, KPCo did not receive a TEA credit for this equipment from the other TEA member companies. The amount involved is $7 million annually. It was not discovered until February 2009. KPCo's base electric rates were adjusted only once, in April 2006, during the period in which the error was in effect. In 2009, the allocation was revised to give KPCo its full TEA credit, effective January 2009, and the KPSC staff and attending intervenors were informed about the revision at a meeting in April 2009. Management does not believe that it is probable that a material retroactive rate adjustment will result. However, if a retroactive adjustment is required, it could have an adverse effect on future net income, cash flows and financial condition.

4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on the financial statements. The Commitments, Guarantees and Contingencies note within the 2008 Annual Report should be read in conjunction with this report.

GUARANTEES

There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties.

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. Prior to March 31, 2009, KPCo entered into sale agreements including indemnifications with a maximum exposure that was not significant. There are no material liabilities recorded for any indemnifications.

KPCo, along with the other AEP East companies, PSO and SWEPCo, are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to power purchase and sale activity conducted pursuant to the SIA.

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. GE Capital Commercial Inc. (GE) notified management in November 2008 that they elected to terminate the Master Leasing Agreements in accordance with the termination rights specified within the contract. In 2011, KPCo will be required to purchase all equipment under the lease and pay GE an amount equal to the unamortized value of all equipment then leased. In December 2008, management signed new master lease agreements with one-year commitment periods that include lease terms of up to 10 years. Management expects to enter into replacement leasing arrangements for the equipment affected by this notification prior to the termination date of 2011.

For equipment under the GE master lease agreements that expire prior to 2011, the lessor is guaranteed receipt of up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, KPCo is committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. Under the new master lease agreements, the lessor is guaranteed receipt of up to 68% of the unamortized balance at the end of the lease term. If the actual fair market value of the leased equipment is below the unamortized balance at the end of the lease term, KPCo is committed to pay the difference between the actual fair market value and unamortized balance, with the total guarantee not to exceed 68% of the unamortized balance. At March 31, 2009, the maximum potential loss for these lease agreements was approximately $317 thousand assuming the fair market value of the equipment is zero at the end of the lease term. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance.

CONTINGENCIES

Carbon Dioxide (CO_2) 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 dismissal of this lawsuit was appealed to the Second Circuit Court of Appeals. Briefing and oral argument concluded in 2006. In April 2007, the U.S. Supreme Court issued a decision holding that the Federal EPA has authority to regulate emissions of CO_2 and other greenhouse gases under the CAA, which may impact the Second Circuit's analysis of these issues. The Second Circuit requested supplemental briefs addressing the impact of the Supreme Court's decision on this case which were provided in 2007. Management believes the actions are without merit and intends to defend against the claims.

Alaskan Villages' Claims

In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil & 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. The defendants filed motions to dismiss the action. The motions are pending before the court. Management believes the action is without merit and intends to defend against the claims.

FERC Long-term Contracts

In 2002, the FERC held a hearing related to a complaint filed by Nevada Power Company and Sierra Pacific Power Company (the Nevada utilities). The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were "high-priced." The complaint alleged that KPCo and other AEP subsidiaries sold power at unjust and unreasonable prices because the market for power was allegedly dysfunctional at the time such contracts were executed. In 2003, the FERC rejected the complaint. In 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC order and remanded the case to the FERC for further proceedings. That decision was appealed to the U.S. Supreme Court. In June 2008, the U.S. Supreme Court affirmed the validity of contractually-agreed rates except in cases of serious harm to the public. The U.S. Supreme Court affirmed the Ninth Circuit's remand on two issues, market manipulation and excessive burden on consumers. The FERC initiated remand procedures and gave the parties time to attempt to settle the issues. Management believes a provision recorded in 2008 should be sufficient. Management asserted claims against certain companies that sold power to KPCo and other AEP subsidiaries, which was resold to the Nevada utilities, seeking to recover a portion of any amounts that may be owed to the Nevada utilities. Management is unable to predict the outcome of these proceedings or their impact on future net income and cash flows.

5. BENEFIT PLANS

KPCo participates in AEP sponsored qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. In addition, KPCo participates in other postretirement benefit plans sponsored by AEP to provide medical and death benefits for retired employees.

Components of Net Periodic Benefit Cost

The following table provides the components of AEP's net periodic benefit cost for the plans for the three months ended March 31, 2009 and 2008:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2009	2008	2009	2008
	(in millions)			
Service Cost	$ 26	$ 25	$ 10	$ 10
Interest Cost	63	63	27	28
Expected Return on Plan Assets	(80)	(84)	(20)	(28)
Amortization of Transition Obligation	-	-	7	7
Amortization of Net Actuarial Loss	15	9	11	3
Net Periodic Benefit Cost	$ 24	$ 13	$ 35	$ 20

The following table provides KPCo's net periodic benefit cost for the plans for the three months ended March 31, 2009 and 2008:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2009	2008	2009	2008
	(in thousands)			
Net Periodic Benefit Cost	$ 555	$ 249	$ 808	$ 401

AEP sponsors several trust funds with significant investments intended to provide for future pension and OPEB payments. All of the trust funds' investments are well-diversified and managed in compliance with all laws and regulations. The value of the investments in these trusts has declined from the December 31, 2008 balances due to decreases in the equity and fixed income markets. Although the asset values are currently lower than at year end, this decline has not affected the funds' ability to make their required payments.

6. BUSINESS SEGMENTS

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

7. DERIVATIVES, HEDGING AND FAIR VALUE MEASUREMENTS

DERIVATIVES AND HEDGING

Objectives for Utilization of Derivative Instruments

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

Strategies for Utilization of Derivative Instruments to Achieve Objectives

The strategy surrounding the use of derivative instruments focuses on managing risk exposures, future cash flows and creating value based on open trading positions by utilizing both economic and formal SFAS 133 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 SFAS 133. Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of SFAS 133.

AEPSC, on behalf of KPCo, enters into electricity, coal, natural gas, interest rate and to a lesser degree heating oil, gasoline, emission allowance and other commodity contracts to manage the risk associated with the energy business. AEPSC, on behalf of KPCo, enters into interest rate derivative contracts in order to manage the interest rate exposure associated with KPCo's commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. AEPSC, on behalf of KPCo, also engages in risk management of interest rate risk associated with debt financing. The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with the established risk management policies as approved by the Finance Committee of AEP's Board of Directors.

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

Notional Volume of Derivative Instruments
March 31, 2009

Primary Risk Exposure	Volume	Unit of Measure
	(in thousands)	
Commodity:		
Power	20,706	MWHs
Coal	1,692	Tons
Natural Gas	7,647	MMBtus
Heating Oil and Gasoline	227	Gallons
Interest Rate	$ 8,279	USD
Interest Rate	$ -	USD

Fair Value Hedging Strategies

At certain times, AEPSC, on behalf of KPCo, enters into interest rate derivative transactions in order to manage existing fixed interest rate risk exposure. These interest rate derivative transactions effectively modify KPCo's exposure to interest rate risk by converting a portion of KPCo's fixed-rate debt to a floating rate. During 2009 and 2008, this strategy was not actively employed.

Cash Flow Hedging Strategies

AEPSC, on behalf of KPCo, enters into and designates as cash flow hedges certain derivative transactions for the purchase and sale of electricity, coal and natural gas ("Commodity") in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. KPCo monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and fuel or energy purchases. KPCo does not hedge all commodity price risk. During 2009 and 2008, KPCo designated cash flow hedging relationships using these commodities.

KPCo's vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of KPCo, enters into financial gasoline and heating oil derivative contracts in order mitigate price risk of future fuel purchases. KPCo does not hedge all of fuel price risk. During 2009, KPCo designated cash flow hedging strategies of forecasted fuel purchases. This strategy was not active for KPCo during 2008. For disclosure purposes, these contracts are included with other hedging activity as "Commodity."

AEPSC, on behalf of KPCo, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. KPCo enters into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. The anticipated fixed-rate debt offerings have a high probability of occurrence as the proceeds will be used to fund existing debt maturities and projected capital expenditures. KPCo does not hedge all interest rate exposure. During 2009 and 2008, KPCo did not have any active interest rate cash flow hedge strategies.

Accounting for Derivative Instruments and the Impact on KPCo's Financial Statements

SFAS 133 requires recognition of all qualifying derivative instruments as either assets or liabilities in the balance sheet at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, KPCo applies valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract's term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with management's estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions, margin requirements and the timing of settlement of KPCo's risk management contracts.

According to FSP FIN 39-1, 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 March 31, 2009 and December 31, 2008 balance sheets, KPCo netted $5 million and $468 thousand of cash collateral received from third parties against short-term and long-term risk management assets and $7.3 million and $1.2 million of cash collateral paid to third parties against short-term and long-term risk management liabilities, respectively.

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

Fair Value of Derivative Instruments
March 31, 2009
(in thousands)

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate and Foreign Currency**	**Other (b)**	**Total**
Current Risk Management Assets	$ 131,854	$ 1,621	$ -	$ (118,817)	$ 14,658
Long-Term Risk Management Assets	54,478	124	-	(41,635)	12,967
Total Assets	186,332	1,745	-	(160,452)	27,625
Current Risk Management Liabilities	126,479	406	-	(119,245)	7,640
Long-Term Risk Management Liabilities	50,905	84	-	(44,965)	6,024
Total Liabilities	177,384	490	-	(164,210)	13,664
Total MTM Derivative Contract Net Assets (Liabilities)	$ 8,948	$ 1,255	$ -	$ 3,758	$ 13,961

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented in the Condensed Balance Sheets on a net basis in accordance with FIN 39 "Offsetting of Amounts Related to Certain Contracts."
(b) Amounts represent counterparty netting of risk management contracts, associated cash collateral in accordance with FSP FIN 39-1 and dedesignated risk management contracts.

The table below presents KPCo's MTM activity of derivative risk management contracts for the three months ended March 31, 2009:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended March 31, 2009

Location of Gain (Loss)	**(in thousands)**
Electric Generation, Transmission and Distribution Revenues	$ 8,049
Sales to AEP Affiliates	(1,526)
Regulatory Assets	-
Regulatory Liabilities	1,464
Total Gain on Risk Management Contracts	$ 7,987

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in SFAS 133. Derivative contracts that have been designated as normal purchases or normal sales under SFAS 133 are not subject to MTM accounting treatment and are recognized in the Condensed Consolidated Statements of Income on an accrual basis.

KPCo's accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, KPCo designates a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Realized gains and losses on derivative instruments held for trading purposes are included in Revenues on a net basis in KPCo's Condensed Statements of Income. Realized gains and losses on derivative instruments not held for trading purposes are included in Revenues or Expenses on KPCo's Condensed Statements of Income depending on the relevant facts and circumstances. Unrealized and realized gains and losses for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains), in accordance with SFAS 71.

Accounting for Fair Value Hedging Strategies

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof attributable to a particular risk), KPCo recognizes the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item associated with the hedged risk in Net Income during the period of change.

KPCo records realized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged, in Interest Expense on KPCo's Condensed Statements of Income. During the three months ended March 31, 2009 and 2008, this strategy was not actively employed.

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 Condensed Balance Sheets until the period the hedged item affects Net Income. KPCo recognizes any hedge ineffectiveness as a regulatory asset (for losses) or a regulatory liability (for gains) in accordance with SFAS 71.

Realized gains and losses on derivatives transactions for the purchase and sale of electricity, coal and natural gas designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale in KPCo's Condensed Statements of Income, depending on the specific nature of the risk being hedged. KPCo does not hedge all variable price risk exposure related to commodities. During the three months ended March 31, 2009 and 2008, KPCo recognized immaterial amounts in Net Income related to hedge ineffectiveness.

Beginning in 2009, KPCo executed financial heating oil and gasoline derivative contracts to hedge the price risk of its diesel fuel and gasoline purchased. KPCo reclassifies gains and losses on financial fuel derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on the Condensed Balance Sheets into Other Operation and Maintenance Expense or Depreciation and Amortization Expense, as it relates to Capital projects, on the Condensed Statements of Income. KPCo does not hedge all fuel price exposure. During the three months ended March 31, 2009, KPCo recognized no hedge ineffectiveness related to this hedge strategy.

KPCo reclassifies gains and losses on interest rate derivative hedges related to debt financing from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During the three months ended March 31, 2009 and 2008, this strategy was not actively employed.

The following table provides details on designated, effective cash flow hedges included in AOCI on KPCo's Condensed Balance Sheets and the reasons for changes in cash flow hedges from January 1, 2009 to March 31, 2009. All amounts in the following table are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Three Months Ended March 31, 2009
(in thousands)

	Commodity	Interest Rate	Total
Beginning Balance in AOCI as of January 1, 2009	$ 584	$ (525)	$ 59
Changes in Fair Value Recognized in AOCI	38	-	38
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet			
Electric Generation, Transmission and Distribution Revenues	(233)	-	(233)
Purchased Electricity for Resale	428	-	428
Interest Expense	-	16	16
Ending Balance in AOCI as of March 31, 2009	$ 817	$ (509)	$ 308

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

Impact of Cash Flow Hedges on the Condensed Balance Sheet

	Commodity	Interest Rate (in thousands)	Total
Hedging Assets (a)	$ 1,372	$ -	$ 1,372
Hedging Liabilities (a)	(117)	-	(117)
AOCI Gain (Loss) Net of Tax	817	(509)	308
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	791	(60)	731

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

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of March 31, 2009, the maximum length of time that KPCo is hedging (with SFAS 133 designated contracts) exposure to variability in future cash flows related to forecasted transactions is 14 months.

Credit Risk

Management limits credit risk in KPCo's wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. KPCo uses Moody's, S&P and current market-based qualitative and quantitative data to assess the financial health of counterparties on an ongoing basis. If an external rating is not available, an internal rating is generated utilizing a quantitative tool developed by Moody's to estimate probability of default that corresponds to an implied external agency credit rating.

KPCo uses standardized master agreements which may include collateral requirements. These master agreements facilitate the netting of cash flows associated with a single counterparty. Cash, letters of credit, and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's credit policy. In addition, collateral agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Under a limited number of derivative and non-derivative counterparty contracts primarily related to pre-2002 risk management activities and under the tariffs of the RTOs and Independent System Operators (ISOs), KPCo is obligated to post an amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, the risk management organization assesses the appropriateness of these collateral triggering items in contracts. Management believes that a downgrade below investment grade is unlikely. As of March 31, 2009, the aggregate value of such contracts was $7.8 million and KPCo was not required to post any collateral. KPCo would have been required to post $7.8 million of collateral at March 31, 2009, if certain credit ratings had declined below investment grade of which $7.7 million was attributable to RTO and ISO activities.

FAIR VALUE MEASUREMENTS

SFAS 157 Fair Value Measurements

As described in KPCo's 2008 Annual Report, SFAS 157 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). The Derivatives, Hedging and Fair Value Measurements note within KPCo's 2008 Annual Report should be read in conjunction with this report.

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 March 31, 2009 and December 31, 2008. As required by SFAS 157, 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.

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of March 31, 2009

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Contracts (a)	$ 3,671	$ 178,812	$ 3,296	$ (161,982)	$ 23,797
Cash Flow and Fair Value Hedges (a)	-	1,745	-	(373)	1,372
Dedesignated Risk Management Contracts (b)	-	-	-	2,456	2,456
Total Risk Management Assets	$ 3,671	$ 180,557	$ 3,296	$ (159,899)	$ 27,625
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 4,046	$ 171,880	$ 905	$ (164,196)	$ 12,635
Cash Flow and Fair Value Hedges (a)	-	490	-	(373)	117
DETM Assignment (c)	-	-	-	912	912
Total Risk Management Liabilities	$ 4,046	$ 172,370	$ 905	$ (163,657)	$ 13,664

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

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

(a) Amounts in "Other" column primarily represent counterparty netting of risk management contracts and associated cash collateral under FSP FIN 39-1.

(b) "Dedesignated Risk Management Contracts" are contracts that were originally MTM but were subsequently elected as normal under SFAS 133. At the time of the normal election, the MTM value was frozen and no longer fair valued. This will be amortized into revenues over the remaining life of the contract.

(c) See "Natural Gas Contracts with DETM" section of Note 12 in KPCo's 2008 Annual Report.

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

Three Months Ended March 31, 2009	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of January 1, 2009	$ 1,713
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)	(834)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements	-
Transfers in and/or out of Level 3 (b)	(16)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	1,528
Balance as of March 31, 2009	$ 2,391

Three Months Ended March 31, 2008		Net Risk Management Assets (Liabilities)
		(in thousands)
Balance as of January 1, 2008	$	(157)
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)		(131)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)		-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income		-
Purchases, Issuances and Settlements		-
Transfers in and/or out of Level 3 (b)		(210)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)		293
Balance as of March 31, 2008	$	(205)

(a) Included in revenues on KPCo's Condensed Statements of Income.

(b) "Transfers in and/or out of Level 3" represent 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.

(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected on KPCo's Condensed Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets.

8. INCOME TAXES

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2000. KPCo and other AEP subsidiaries have completed the exam for the years 2001 through 2006 and have issues that are being pursued at the appeals level. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on net income.

9. FINANCING ACTIVITIES

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding borrowings from the Utility Money Pool as of March 31, 2009 and December 31, 2008 are included in Advances from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the three months ended March 31, 2009 are described in the following table:

Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Borrowings from Utility Money Pool as of March 31, 2009	Authorized Short-Term Borrowing Limit
		(in thousands)			
$ 161,838	$ -	$ 145,160	$ -	$ 157,290	$ 250,000

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

	Maximum Interest Rates for Funds Borrowed from the Utility Money Pool	Minimum Interest Rates for Funds Borrowed from the Utility Money Pool	Maximum Interest Rates for Funds Loaned to the Utility Money Pool	Minimum Interest Rates For Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2009	2.28%	1.22%	-%	-%	1.69%	-%
2008	5.37%	3.39%	-%	-%	4.09%	-%

Credit Facilities

KPCo and certain other companies in the AEP System have a $650 million 3-year credit agreement and a $350 million 364-day credit agreement which were reduced by Lehman Brothers Holdings Inc.'s commitment amount of $23 million and $12 million, respectively, following its bankruptcy. Under the facilities, letters of credit may be issued. As of March 31, 2009, there were no outstanding amounts for KPCo under either facility. In April 2009, the $350 million 364-day credit agreement expired.