# Kentucky Power Company

2008 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 |
|---|---|
| AEP or Parent | American Electric Power Company, Inc. |
| AEP East companies | APCo, CSPCo, I&M, KPCo and OPCo. |
| AEP System or the 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. |
| APCo | Appalachian Power Company, an AEP electric utility subsidiary. |
| 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.). |
| 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 48 | FIN 48, "Accounting for Uncertainty in Income Taxes" and FASB Staff Position FIN 48-1 "Definition of *Settlement* in FASB Interpretation No. 48." |
| GAAP | Accounting Principles Generally Accepted in the United States of America. |
| IRS | Internal Revenue Service. |
| 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. |
| MTM | Mark-to-Market. |
| OPCo | Ohio Power Company, an AEP electric utility subsidiary. |
| OTC | Over the counter. |
| 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. |
| RTO | Regional Transmission Organization. |
| SECA | Seams Elimination Cost Allocation. |
| 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." |

| Term | Meaning |
|---|---|
| SFAS 159 | Statement of Financial Accounting Standards No. 159, “The Fair Value Option for Financial Assets and Financial Liabilities.” |
| 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, 2008 and 2007**
**(in thousands)**
**(Unaudited)**

| | 2008 | 2007 |
|---|---|---|
| **REVENUES** | | |
| Electric Generation, Transmission and Distribution | $ 147,059 | $ 140,486 |
| Sales to AEP Affiliates | 20,053 | 13,461 |
| Other | 178 | 149 |
| **TOTAL** | 167,290 | 154,096 |
| **EXPENSES** | | |
| Fuel and Other Consumables Used for Electric Generation | 49,211 | 38,304 |
| Purchased Electricity for Resale | 3,766 | 3,305 |
| Purchased Electricity from AEP Affiliates | 54,190 | 43,257 |
| Other Operation | 15,508 | 15,886 |
| Maintenance | 9,920 | 8,210 |
| Depreciation and Amortization | 11,958 | 11,796 |
| Taxes Other Than Income Taxes | 1,180 | 2,803 |
| **TOTAL** | 145,733 | 123,561 |
| **OPERATING INCOME** | 21,557 | 30,535 |
| **Other Income (Expense):** | | |
| Interest Income | 1,288 | 112 |
| Allowance for Equity Funds Used During Construction | 344 | 14 |
| Interest Expense | (6,855) | (7,011) |
| **INCOME BEFORE INCOME TAX EXPENSE** | 16,334 | 23,650 |
| Income Tax Expense | 5,190 | 8,439 |
| **NET INCOME** | $ 11,144 | $ 15,211 |

*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, 2008 and 2007**
**(in thousands)**
**(Unaudited)**

| | Common Stock | Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
|---|---|---|---|---|---|
| **DECEMBER 31, 2006** | $ 50,450 | $ 208,750 | $ 108,899 | $ 1,552 | $ 369,651 |
| FIN 48 Adoption, Net of Tax | | | (786) | | (786) |
| Common Stock Dividends | | | (5,000) | | (5,000) |
| **TOTAL** | | | | | 363,865 |
| **COMPREHENSIVE INCOME** | | | | | |
| **Other Comprehensive Loss, Net of Taxes:** | | | | | |
| Cash Flow Hedges, Net of Tax of $1,100 | | | | (2,042) | (2,042) |
| **NET INCOME** | | | 15,211 | | 15,211 |
| **TOTAL COMPREHENSIVE INCOME** | | | | | 13,169 |
| **MARCH 31, 2007** | $ 50,450 | $ 208,750 | $ 118,324 | $ (490) | $ 377,034 |
| **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 |

*See Condensed Notes to Condensed Financial Statements.*

**KENTUCKY POWER COMPANY**
**CONDENSED BALANCE SHEETS**
**ASSETS**
**March 31, 2008 and December 31, 2007**
**(in thousands)**
**(Unaudited)**

| | 2008 | 2007 |
|---|---|---|
| **CURRENT ASSETS** | | |
| Cash and Cash Equivalents | $ 889 | $ 727 |
| Accounts Receivable: | | |
| Customers | 21,974 | 20,196 |
| Affiliated Companies | 8,436 | 15,984 |
| Accrued Unbilled Revenues | 5,195 | 2,904 |
| Miscellaneous | 383 | 178 |
| Allowance for Uncollectible Accounts | (1,089) | (1,071) |
| Total Accounts Receivable | 34,899 | 38,191 |
| Fuel | 13,997 | 8,338 |
| Materials and Supplies | 11,762 | 11,758 |
| Risk Management Assets | 29,000 | 12,121 |
| Regulatory Asset for Under-Recovered Fuel Costs | - | 4,426 |
| Prepayments and Other | 4,930 | 4,024 |
| **TOTAL** | 95,477 | 79,585 |
| **PROPERTY, PLANT AND EQUIPMENT** | | |
| Electric: | | |
| Production | 483,590 | 482,653 |
| Transmission | 402,644 | 402,259 |
| Distribution | 508,684 | 502,486 |
| Other | 63,088 | 61,665 |
| Construction Work in Progress | 55,348 | 46,439 |
| **Total** | 1,513,354 | 1,495,502 |
| Accumulated Depreciation and Amortization | 462,931 | 457,028 |
| **TOTAL - NET** | 1,050,423 | 1,038,474 |
| **OTHER NONCURRENT ASSETS** | | |
| Regulatory Assets | 126,862 | 124,828 |
| Long-term Risk Management Assets | 15,846 | 14,826 |
| Deferred Charges and Other | 52,634 | 53,708 |
| **TOTAL** | 195,342 | 193,362 |
| **TOTAL ASSETS** | $ 1,341,242 | $ 1,311,421 |

*See Condensed Notes to Condensed Financial Statements.*

# KENTUCKY POWER COMPANY
## CONDENSED BALANCE SHEETS
## LIABILITIES AND SHAREHOLDER'S EQUITY
## March 31, 2008 and December 31, 2007
## (Unaudited)

| | 2008 | 2007 |
|---|---|---|
| | (in thousands) | |
| **CURRENT LIABILITIES** | | |
| Advances from Affiliates | $ 40,305 | $ 19,153 |
| Accounts Payable: | | |
| General | 32,155 | 32,603 |
| Affiliated Companies | 19,451 | 29,437 |
| Long-term Debt Due Within One Year – Nonaffiliated | 30,000 | 30,000 |
| Risk Management Liabilities | 30,089 | 10,310 |
| Customer Deposits | 14,954 | 14,422 |
| Accrued Taxes | 16,915 | 16,875 |
| Regulatory Liability for Over-Recovered Fuel Costs | 1,299 | - |
| Other | 18,342 | 31,909 |
| **TOTAL** | 203,510 | 184,709 |
| **NONCURRENT LIABILITIES** | | |
| Long-term Debt – Nonaffiliated | 398,419 | 398,373 |
| Long-term Debt – Affiliated | 20,000 | 20,000 |
| Long-term Risk Management Liabilities | 11,159 | 9,699 |
| Deferred Income Taxes | 244,087 | 240,858 |
| Regulatory Liabilities and Deferred Investment Tax Credits | 45,943 | 46,434 |
| Deferred Credits and Other | 25,211 | 24,379 |
| **TOTAL** | 744,819 | 739,743 |
| **TOTAL LIABILITIES** | 948,329 | 924,452 |
| 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 | 136,862 | 128,583 |
| Accumulated Other Comprehensive Income (Loss) | (3,149) | (814) |
| **TOTAL** | 392,913 | 386,969 |
| **TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY** | $ 1,341,242 | $ 1,311,421 |

*See Condensed Notes to Condensed Financial Statements.*

**KENTUCKY POWER COMPANY**
**CONDENSED STATEMENTS OF CASH FLOWS**
**For the Three Months Ended March 31, 2008 and 2007**
**(in thousands)**
**(Unaudited)**

| | 2008 | 2007 |
|---|---|---|
| **OPERATING ACTIVITIES** | | |
| **Net Income** | $ 11,144 | $ 15,211 |
| **Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:** | | |
| Depreciation and Amortization | 11,958 | 11,796 |
| Deferred Income Taxes | (979) | 956 |
| Allowance for Equity Funds Used During Construction | (344) | (14) |
| Mark-to-Market of Risk Management Contracts | (749) | 313 |
| Change in Other Noncurrent Assets | (888) | 994 |
| Change in Other Noncurrent Liabilities | 246 | (78) |
| **Changes in Certain Components of Working Capital:** | | |
| Accounts Receivable, Net | 3,292 | (1,350) |
| Fuel, Materials and Supplies | (5,663) | 3,609 |
| Accounts Payable | (5,119) | (2,557) |
| Customer Deposits | 532 | 395 |
| Accrued Taxes, Net | 811 | 1,447 |
| Other Current Assets | 2,748 | 574 |
| Other Current Liabilities | (7,618) | (3,348) |
| **Net Cash Flows from Operating Activities** | 9,371 | 27,948 |
| **INVESTING ACTIVITIES** | | |
| Construction Expenditures | (27,784) | (13,001) |
| Proceeds from Sales of Assets | 129 | 231 |
| **Net Cash Flows Used for Investing Activities** | (27,655) | (12,770) |
| **FINANCING ACTIVITIES** | | |
| Change in Advances from Affiliates, Net | 21,152 | (9,867) |
| Principal Payments for Capital Lease Obligations | (206) | (238) |
| Dividends Paid on Common Stock | (2,500) | (5,000) |
| **Net Cash Flows from (Used for) Financing Activities** | 18,446 | (15,105) |
| **Net Increase in Cash and Cash Equivalents** | 162 | 73 |
| **Cash and Cash Equivalents at Beginning of Period** | 727 | 702 |
| **Cash and Cash Equivalents at End of Period** | $ 889 | $ 775 |
| **SUPPLEMENTARY INFORMATION** | | |
| Cash Paid for Interest, Net of Capitalized Amounts | $ 10,934 | $ 5,371 |
| Net Cash Paid (Received) for Income Taxes | (354) | 738 |
| Noncash Acquisitions Under Capital Leases | 84 | 139 |
| Construction Expenditures Included in Accounts Payable at March 31, | 6,846 | 2,257 |

*See Condensed Notes to Condensed Financial Statements.*

## CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

## 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 results of operations, financial position and cash flows for the interim periods. The results of operations for the three months ended March 31, 2008 are not necessarily indicative of results that may be expected for the year ending December 31, 2008. The accompanying condensed financial statements are unaudited and should be read in conjunction with the audited 2007 financial statements and notes thereto, which are included in KPCo's 2007 Annual Report.

### *Reclassifications*

Certain prior period financial statement items have been reclassified to conform to current period presentation. See "FASB Staff Position FIN 39-1 Amendment of FASB Interpretation No. 39" section of Note 2 for discussion of changes in netting certain balance sheet amounts. These revisions had no impact on KPCo's previously reported results of operations or changes in shareholder's equity.

## 2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management thoroughly 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 2008 and standards issued but not implemented that management has determined relate to KPCo's operations.

### *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 establishes 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. SFAS 141R 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 is effective prospectively for business combinations with an acquisition date on or after the beginning of the first annual reporting period after December 15, 2008. Early adoption is prohibited. KPCo will adopt SFAS 141R effective January 1, 2009 and apply it to any business combinations on or after that date.

### *SFAS 157 "Fair Value Measurements" (SFAS 157)*

In September 2006, the FASB issued SFAS 157, enhancing existing guidance for fair value measurement of assets and liabilities and instruments measured at fair value that are classified in shareholder's equity. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures. It emphasizes that fair value is market-based with the highest measurement hierarchy level being market prices in active markets. The standard requires fair value measurements be disclosed by hierarchy level, an entity include its own credit standing in the measurement of its liabilities and modifies the transaction price presumption. The standard also nullifies the consensus reached in EITF Issue No. 02-3 "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-3) that prohibited the recognition of trading gains or losses at the inception of a derivative contract, unless the fair value of such derivative is supported by observable market data.

In February 2008, the FASB issued FASB Staff Position (FSP) FAS 157-1 "Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13" which amends SFAS 157 to exclude SFAS 13 "Accounting for Leases" and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under SFAS 13.

In February 2008, the FASB issued FSP FAS 157-2 "Effective Date of FASB Statement No. 157" 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).

KPCo partially adopted SFAS 157 effective January 1, 2008. KPCo will fully adopt SFAS 157 effective January 1, 2009 for items within the scope of FSP FAS 157-2. The provisions of SFAS 157 are applied prospectively, except for a) changes in fair value measurements of existing derivative financial instruments measured initially using the transaction price under EITF 02-3, b) existing hybrid financial instruments measured initially at fair value using the transaction price and c) blockage discount factors. Although the statement is applied prospectively upon adoption, in accordance with the provisions of SFAS 157 related to EITF 02-3, amounts for transition adjustment are recorded to beginning retained earnings. The impact of considering AEP's own credit risk when measuring the fair value of liabilities, including derivatives, had an immaterial impact on KPCo's fair value measurements upon adoption.

In accordance with SFAS 157, assets and liabilities are classified based on the inputs utilized in the fair value measurement. SFAS 157 provides definitions for two types of inputs: observable and unobservable. Observable inputs are valuation inputs that reflect the assumptions market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the reporting entity. Unobservable inputs are valuation inputs that reflect the reporting entity's own assumptions about the assumptions market participants would use in pricing the asset or liability developed based on the best information in the circumstances.

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 (exit price). 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).

Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 1 inputs primarily consist of exchange traded contracts, listed equities and U.S. government treasury securities that exhibit sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, exchange traded contracts where there was not sufficient market activity to warrant inclusion in Level 1, OTC broker quotes that are corroborated by the same or similar transactions that have occurred in the market and certain non-exchange-traded debt securities.

Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that the observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Level 3 inputs primarily consist of unobservable market data or are valued based on models and/or assumptions.

Risk Management Contracts include exchange traded, OTC and bilaterally executed derivative contracts. Exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified within level 1. Other actively traded derivatives are valued using broker or dealer quotations, similar observable market transactions in either the listed or OTC markets, or through pricing models where significant valuation inputs are directly or indirectly observable in active markets. Derivative instruments, primarily swaps, forwards, and options that meet these characteristics are classified within level 2. Bilaterally executed agreements are derivative contracts entered into directly with third parties, and at times these instruments may be complex structured transactions that are tailored to meet the specific customer's energy requirements. Structured transactions utilize pricing models that are widely accepted in the energy industry to measure fair value. Generally, management uses a consistent modeling approach to value similar instruments. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data), and other observable inputs for the asset or liability. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in level 2. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. In addition, long-dated and illiquid complex or structured transactions 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 in level 3. In certain instances, the fair values of the transactions that use internally developed model inputs, classified as level 3 are offset partially or in full, by transactions included in level 2 where observable market data exists for the offsetting transaction.

The following table sets 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, 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, 2008**

| | Level 1 | Level 2 | Level 3 | Other | Total |
|---|---|---|---|---|---|
| **Assets:** | | | (in thousands) | | |
| **Risk Management Assets:** | | | | | |
| Risk Management Contracts (a) | $ 3,131 | $ 141,881 | $ 2,102 | $ (106,376) | $ 40,738 |
| Cash Flow and Fair Value Hedges (a) | - | 1,261 | - | (598) | 663 |
| Dedesignated Risk Management Contracts (b) | - | - | - | 3,445 | 3,445 |
| **Total Risk Management Assets** | $ 3,131 | $ 143,142 | $ 2,102 | $ (103,529) | $ 44,846 |
| **Liabilities:** | | | | | |
| **Risk Management Liabilities:** | | | | | |
| Risk Management Contracts (a) | $ 4,085 | $ 135,492 | $ 2,307 | $ (107,319) | $ 34,565 |
| Cash Flow and Fair Value Hedges (a) | - | 5,562 | - | (598) | 4,964 |
| DETM Assignment (c) | - | - | - | 1,719 | 1,719 |
| **Total Risk Management Liabilities** | $ 4,085 | $ 141,054 | $ 2,307 | $ (106,198) | $ 41,248 |

(a) Amounts in "Other" column primarily represent counterparty netting of risk management contracts and associated cash collateral under 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 16 in the 2007 Annual Report.

The following table sets forth a reconciliation primarily of changes in the fair value of net trading derivatives and other investments classified as level 3 in the fair value hierarchy:

| | Net Risk Management Assets (Liabilities) |
|---|---|
| | (in thousands) |
| **Balance as of January 1, 2008** | $ (157) |
| Realized (Gain) Loss Included in Earnings (or Changes in Net Assets) (a) | (131) |
| Unrealized Gain (Loss) Included in Earnings (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 Statement of Income for the Three Months Ended March 31, 2008.

(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 the Condensed Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities.

***SFAS 159 "The Fair Value Option for Financial Assets and Financial Liabilities" (SFAS 159)***

In February 2007, the FASB issued SFAS 159, permitting entities to choose to measure many financial instruments and certain other items at fair value. The standard also establishes presentation and disclosure requirements designed to facilitate comparison between entities that choose different measurement attributes for similar types of assets and liabilities. If the fair value option is elected, the effect of the first remeasurement to fair value is reported as a cumulative effect adjustment to the opening balance of retained earnings. The statement is applied prospectively upon adoption.

KPCo adopted SFAS 159 effective January 1, 2008. At adoption, KPCo did not elect the fair value option for any assets or liabilities.

***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.

SFAS 160 is effective for interim and annual periods in fiscal years beginning after December 15, 2008. The statement is applied prospectively upon adoption. Early adoption is prohibited. Upon adoption, prior period financial statements will be restated for the presentation of the noncontrolling interest for comparability. Although management has not completed its analysis, management expects that the adoption of this standard will have an immaterial impact on the financial statements. KPCo will adopt SFAS 160 effective January 1, 2009.

***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 derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. SFAS 161 requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. This standard is intended to improve upon the existing disclosure framework in SFAS 133.

SFAS 161 is effective for fiscal years and interim periods beginning after November 15, 2008. Management expects this standard to increase the disclosure requirements related to derivative instruments and hedging activities. It encourages retrospective application to comparative disclosure for earlier periods presented. KPCo will adopt SFAS 161 effective January 1, 2009.

***EITF Issue No. 06-10 "Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements" (EITF 06-10)***

In March 2007, the FASB ratified EITF 06-10, a consensus on collateral assignment split-dollar life insurance arrangements in which an employee owns and controls the insurance policy. Under EITF 06-10, an employer should recognize a liability for the postretirement benefit related to a collateral assignment split-dollar life insurance arrangement in accordance with SFAS 106 "Employers' Accounting for Postretirement Benefits Other Than Pension" or Accounting Principles Board Opinion No. 12 "Omnibus Opinion – 1967" if the employer has agreed to maintain a life insurance policy during the employee's retirement or to provide the employee with a death benefit based on a substantive arrangement with the employee. In addition, an employer should recognize and measure an asset based on the nature and substance of the collateral assignment split-dollar life insurance arrangement. EITF 06-10 requires recognition of the effects of its application as either (a) a change in accounting principle through a cumulative effect adjustment to retained earnings or other components of equity or net assets in the statement of financial position at the beginning of the year of adoption or (b) a change in accounting principle through retrospective application to all prior periods. KPCo adopted EITF 06-10 effective January 1, 2008 with a cumulative effect reduction of $365 thousand (net of tax of $197 thousand) to beginning earnings.

***EITF Issue No. 06-11 "Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards" (EITF 06-11)***

In June 2007, the FASB ratified the EITF consensus on the treatment of income tax benefits of dividends on employee share-based compensation. The issue is how a company should recognize the income tax benefit received on dividends that are paid to employees holding equity-classified nonvested shares, equity-classified nonvested share units or equity-classified outstanding share options and charged to retained earnings under SFAS 123R, "Share-Based Payments." Under EITF 06-11, a realized income tax benefit from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity-classified nonvested equity shares, nonvested equity share units and outstanding equity share options should be recognized as an increase to additional paid-in capital.

KPCo adopted EITF 06-11 effective January 1, 2008. EITF 06-11 is applied prospectively to the income tax benefits of dividends on equity-classified employee share-based payment awards that are declared in fiscal years after September 15, 2007. The adoption of this standard had an immaterial impact on the financial statements.

***FASB Staff Position FIN 39-1 "Amendment of FASB Interpretation No. 39" (FIN 39-1)***

In April 2007, the FASB issued FIN 39-1. It amends FASB Interpretation No. 39, "Offsetting of Amounts Related to Certain Contracts" by replacing the interpretation's definition of contracts with the definition of derivative instruments per SFAS 133. It also requires entities that offset fair values of derivatives with the same party under a netting agreement to also net the fair values (or approximate fair values) of related cash collateral. The entities must disclose whether or not they offset fair values of derivatives and related cash collateral and amounts recognized for cash collateral payables and receivables at the end of each reporting period.

KPCo adopted FIN 39-1 effective January 1, 2008. This standard changed the method of netting certain balance sheet amounts and reduced assets and liabilities. It requires retrospective application as a change in accounting principle. Consequently, KPCo reclassified the following amounts on its December 31, 2007 balance sheet as shown:

| **Balance Sheet Line Description** | **As Reported for the December 2007 10-K** | **FIN 39-1 Reclassification** | **As Reported for the March 2008 10-Q** |
|---|---|---|---|
| Current Assets: | | **(in thousands)** | |
| Risk Management Assets | $ 12,480 | $ (359) | $ 12,121 |
| Prepayments and Other | 4,701 | (677) | 4,024 |
| Long-term Risk Management Assets | 15,356 | (530) | 14,826 |
| | | | |
| Current Liabilities: | | | |
| Risk Management Liabilities | 10,974 | (664) | 10,310 |
| Customer Deposits | 15,312 | (890) | 14,422 |
| Long-term Risk Management Liabilities | 9,711 | (12) | 9,699 |

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, 2008 balance sheet, KPCo netted $1.8 million of cash collateral received from third parties against short-term and long-term risk management assets and $2.7 million of cash collateral paid to third parties against short-term and long-term risk management liabilities.

***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, liabilities and equity, emission allowances, leases, insurance, subsequent events 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 results of operations and financial position.

## 3. RATE MATTERS

As discussed in KPCo's 2007 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within the 2007 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact results of operations, cash flows and possibly financial condition. The following discusses ratemaking developments in 2008 and updates the 2007 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. The KPSC and Duke Energy appealed the Franklin County Circuit Court decision.

Although this order is not directly applicable to KPCo, it is possible that the AG or another intervenor could challenge KPCo's existing surcharges, which are not specifically authorized by statute. These include KPCo's fuel clause surcharge, annual Rockport Plant capacity surcharge, merger surcredit and off-system sales credit rider. These surcharges are currently producing net annual revenues of approximately $10 million. The KPSC has asked interested parties to brief the issue in KPCo's outstanding fuel cost proceeding. The AG stated 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. The appeals process could take up to two years to complete. The AG agreed to stay its challenge during that time. KPCo's exposure is indeterminable at this time since it is not known whether a final adverse appeal could result in a refund of prior amounts collected, which would have an adverse effect on future results of operations and cash flows.

### *2008 Fuel Cost Reconciliation*

In January 2008, KPCo filed its semi-annual fuel cost reconciliation covering the period May 2007 through October 2007. As part of this filing, KPCo sought recovery of incremental costs associated with transmission line losses billed by PJM since June 2007 due to the implementation of marginal loss pricing. KPCo expensed these incremental PJM costs associated with transmission line losses pending a determination that they are recoverable through the Kentucky fuel clause back to June 2007. If recovery of the incremental PJM costs through the fuel clause is denied, future results of operations and cash flows would be adversely affected. A decision is expected in May 2008.

## FERC Rate Matters

### *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 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 AEP and ultimately its internal load customers to make up the short fall in revenues.

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 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. As a result, SECA ratepayers have been willing to engage with AEP in settlement discussions. AEP has been engaged in settlement discussions in an effort to settle the SECA issue. However, if the ALJ's initial decision is upheld in its entirety, it could result in a disallowance of a large portion on any unsettled SECA revenues.

During 2006, the AEP East companies provided reserves of $37 million for net refunds for current and future SECA settlements. After reviewing existing settlements, the AEP East companies increased their reserves by an additional $5 million in December 2007. KPCo provided reserves of $3 million and $400 thousand in 2006 and 2007, respectively.

Completed and in-process settlements cover $105 million of the $220 million of SECA revenues and will consume about $7 million of the reserve for refund, leaving approximately $115 million of contested SECA revenues and $35 million of refund reserves.

If the FERC adopts the ALJ's decision and/or AEP cannot settle the remaining unsettled claims within the amount reserved for refunds, it will have an adverse effect on future results of operations 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 remaining reserve of $35 million is adequate to cover all remaining settlements. KPCo's portion of the reserve is $3 million. However, management cannot predict the ultimate outcome of ongoing settlement discussions or future FERC proceedings or court appeals, if such are necessary.

*The FERC PJM Regional Transmission Rate Proceeding*

With the elimination of T&O rates and the expiration of SECA rates and after considerable administrative litigation at the FERC in which AEP sought to mitigate the effect of 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 regulatory approvals for recovery of any costs of new facilities that are assigned to them. AEP had requested rehearing of this order, which the FERC denied. AEP filed a Petition for Review of the FERC orders in this case in February 2008 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, results of operations and cash flows.

The AEP East companies filed for and in 2006 obtained increases in its 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 to recover lost T&O revenues previously applied to reduce retail rates. As a result, AEP is now recovering approximately 85% of the lost T&O transmission revenues. AEP received net SECA transmission revenues of $128 million in 2005.

*The FERC PJM and MISO Regional Transmission Rate Proceeding*

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 argues 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. Should this effort be successful, KPCo would reduce future retail revenues in their next fuel or base rate proceedings. Management is unable to predict the outcome of this case.

## 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 2007 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, 2008, 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 Operating Lease

KPCo leases certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive 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 has 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. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance. Assuming the fair market value of the equipment is zero at the end of the lease term, the maximum potential loss for these lease agreements was approximately $2 million as of March 31, 2008.

## 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 have concluded. On April 2, 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. 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. 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 and argued before the U.S. Supreme Court in February 2008. Management is unable to predict the outcome of these proceedings or their impact on future results of operations and cash flows. 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.

## 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, 2008 and 2007:

| | Pension Plans | | Other Postretirement Benefit Plans | |
|---|---|---|---|---|
| | Three Months Ended March 31, | | Three Months Ended March 31, | |
| | 2008 | 2007 | 2008 | 2007 |
| | (in millions) | | | |
| Service Cost | $ 25 | $ 24 | $ 10 | $ 10 |
| Interest Cost | 63 | 59 | 28 | 26 |
| Expected Return on Plan Assets | (84) | (85) | (28) | (26) |
| Amortization of Transition Obligation | - | - | 7 | 7 |
| Amortization of Net Actuarial Loss | 9 | 15 | 3 | 3 |
| **Net Periodic Benefit Cost** | $ 13 | $ 13 | $ 20 | $ 20 |

The following table provides KPCo's net periodic benefit cost for the plans for the three months ended March 31, 2008 and 2007:

| | Pension Plans | | Other Postretirement Benefit Plans | |
|---|---|---|---|---|
| | Three Months Ended March 31, | | Three Months Ended March 31, | |
| | 2008 | 2007 | 2008 | 2007 |
| | (in thousands) | | | |
| Net Periodic Benefit Cost | $ 249 | $ 255 | $ 401 | $ 426 |

## 6. BUSINESS SEGMENTS

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

## 7. INCOME TAXES

KPCo adopted FIN 48 as of January 1, 2007. As a result, KPCo recognized an increase in the liabilities for unrecognized tax benefits, as well as related interest expense and penalties, which was accounted for as a reduction to the January 1, 2007 balance of retained earnings.

KPCo joins in the filing of a consolidated federal income tax return with its affiliates in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The tax benefit of the Parent is allocated to its subsidiaries with taxable income. With the exception of the loss of the Parent, the method of allocation reflects a separate return result for each company in the consolidated group.

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2000. However, KPCo and other AEP subsidiaries have filed refund claims with the IRS for years 1997 through 2000 for the CSW pre-merger tax period, which are currently being reviewed. KPCo and other AEP subsidiaries have completed the exam for the years 2001 through 2003 and have issues that will be pursued at the appeals level. The returns for the years 2004 through 2006 are presently under audit by the IRS. 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 results of operations.

KPCo, along with other AEP subsidiaries, files income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns and KPCo and other AEP subsidiaries are currently under examination in several state and local jurisdictions. Management believes that KPCo and other AEP subsidiaries have filed tax returns with positions that may be challenged by these tax authorities. However, management does not believe that the ultimate resolution of these audits will materially impact results of operations. With few exceptions, KPCo is no longer subject to state or local income tax examinations by tax authorities for years before 2000.

### *State Tax Legislation*

In March 2008, the Governor of West Virginia signed legislation providing for, among other things, a reduction in the West Virginia corporate income tax rate from 8.75% to 8.5% beginning in 2009. The corporate income tax rate could also be reduced to 7.75% in 2012 and 7% in 2013 contingent upon the state government achieving certain minimum levels of shortfall reserve funds. Management continues to evaluate the impact of the law change, but does not expect the law change to have a material impact on results of operations, cash flows or financial condition.

On July 12, 2007, the Governor of Michigan signed Michigan Senate Bill 0094 (MBT Act) and related companion bills into law providing a comprehensive restructuring of Michigan's principal business tax. The new law was effective January 1, 2008 and replaced the Michigan Single Business Tax that expired at the end of 2007. The MBT Act is composed of a new tax which will be calculated based upon two components: (a) a business income tax (BIT) imposed at a rate of 4.95% and (b) a modified gross receipts tax (GRT) imposed at a rate of 0.80%, which will collectively be referred to as the BIT/GRT tax calculation. The new law also includes significant credits for engaging in Michigan-based activity.

On September 30, 2007, the Governor of Michigan signed House Bill 5198, which amends the MBT Act to provide for a new deduction on the BIT and GRT tax returns equal to the book-tax basis difference triggered as a result of the enactment of the MBT Act. This new state-only temporary difference will be deducted over a 15- year period on the MBT Act tax returns starting in 2015. The purpose of the new MBT Act state deduction was to provide companies relief from the recordation of the SFAS 109 Income Tax Liability. Management has evaluated the impact of the MBT Act and the application of the MBT Act will not materially affect results of operations, cash flows or financial condition.

## 8. FINANCING ACTIVITIES

### *Lines of Credit*

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 corporate borrowing program 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, 2008 and December 31, 2007 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, 2008 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, 2008 | Authorized Short-Term Borrowing Limit |
|---|---|---|---|---|---|
| | | (in thousands) | | | |
| $ 40,595 | $ - | $ 20,944 | $ - | $ 40,305 | $ 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, 2008 and 2007 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 |
|---|---|---|---|---|---|---|
| 2008 | 5.37% | 3.39% | -% | -% | 4.09% | -% |
| 2007 | 5.43% | 5.30% | -% | -% | 5.34% | -% |

### *Credit Facilities*

In April 2008, the Parent, the AEP East companies and the AEP West companies entered into a $650 million 3-year credit agreement with a third party. Concurrently, the Parent, the AEP East companies and the AEP West companies also entered into a $350 million 364-day credit agreement with a third party.