COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A GENERAL ADJUSTMENT OF ITS RATES FOR ELECTRIC SERVICE; (2) AN ORDER APPROVING ITS 2017 ENVIRONMENTAL COMPLIANCE PLAN; (3) AN ORDER APPROVING ITS TARIFFS AND RIDERS; (4) AN ORDER APPROVING ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND (5) AN ORDER GRANTING ALL OTHER REQUIRED APPROVALS AND RELIEF	**)**	**Case No. 2017-00179**

SECTION II

FILING REQUIREMENTS

VOLUME 7 OF 7

June 28, 2017

Kentucky Power Company

2015 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., an electric utility holding company.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AOCI	Accumulated Other Comprehensive Income.
ASU	Accounting Standards Update.
FASB	Financial Accounting Standards Board.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SIA	System Integration Agreement, effective June 15, 2000, as amended, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2015	2014
REVENUES		
Electric Generation, Transmission and Distribution	$ 199,900	$ 227,631
Sales to AEP Affiliates	1,357	5,415
Other Revenues	192	84
TOTAL REVENUES	201,449	233,130
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	69,199	72,362
Purchased Electricity for Resale	11,796	3,113
Purchased Electricity from AEP Affiliates	23,557	31,422
Other Operation	20,331	19,865
Maintenance	18,289	18,642
Depreciation and Amortization	24,741	23,522
Taxes Other Than Income Taxes	5,604	5,303
TOTAL EXPENSES	173,517	174,229
OPERATING INCOME	27,932	58,901
Other Income (Expense):		
Interest Income	19	33
Allowance for Equity Funds Used During Construction	66	1,456
Interest Expense	(11,037)	(9,101)
INCOME BEFORE INCOME TAX EXPENSE	16,980	51,289
Income Tax Expense	5,982	18,741
NET INCOME	$ 10,998	$ 32,548

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

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014
Net Income	$ 10,998	$ 32,548
OTHER COMPREHENSIVE INCOME, NET OF TAXES		
Cash Flow Hedges, Net of Tax of $8 and $5 in 2015 and 2014, Respectively	15	10
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $9 and $63 in 2015 and 2014, Respectively	16	117
TOTAL OTHER COMPREHENSIVE INCOME	31	127
TOTAL COMPREHENSIVE INCOME	$ 11,029	$ 32,675

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2015 and 2014
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2013	$ 50,450	$ 614,648	$ 179,691	$ (5,420)	$ 839,369
Capital Contribution Returned to Parent		(100,000)			(100,000)
Common Stock Dividends			(15,000)		(15,000)
Other Changes in Common Shareholder's Equity		2,812			2,812
Net Income			32,548		32,548
Other Comprehensive Income				127	127
Pension and OPEB Adjustment Related to Kammer Plant				(1,308)	(1,308)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2014	$ 50,450	$ 517,460	$ 197,239	$ (6,601)	$ 758,548
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2014	$ 50,450	$ 517,460	$ 103,069	$ (7,336)	$ 663,643
Common Stock Dividends			(11,000)		(11,000)
Net Income			10,998		10,998
Other Comprehensive Income				31	31
Pension and OPEB Adjustment Related to Mitchell Plant				5,174	5,174
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2015	$ 50,450	$ 517,460	$ 103,067	$ (2,131)	$ 668,846

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
March 31, 2015 and December 31, 2014
(in thousands)
(Unaudited)

	March 31, 2015	December 31, 2014
CURRENT ASSETS		
Cash and Cash Equivalents	$ 835	$ 795
Accounts Receivable:		
Customers	16,023	21,125
Affiliated Companies	25,304	30,436
Accrued Unbilled Revenues	39	2,047
Miscellaneous	95	131
Allowance for Uncollectible Accounts	(202)	(87)
Total Accounts Receivable	41,259	53,652
Fuel	26,020	45,256
Materials and Supplies	32,151	34,499
Risk Management Assets	2,989	6,358
Deferred Income Tax Benefits	5,991	8,899
Accrued Tax Benefits	14,973	10,944
Regulatory Asset for Under-Recovered Fuel Costs	4,222	—
Prepayments and Other Current Assets	4,100	4,301
TOTAL CURRENT ASSETS	132,540	164,704
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,166,327	1,161,100
Transmission	557,833	558,099
Distribution	735,284	727,569
Other Property, Plant and Equipment (Including Plant to be Retired)	519,682	521,327
Construction Work in Progress	45,358	39,194
Total Property, Plant and Equipment	3,024,484	3,007,289
Accumulated Depreciation and Amortization	1,052,114	1,026,208
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,972,370	1,981,081
OTHER NONCURRENT ASSETS		
Regulatory Assets	241,792	229,827
Long-term Risk Management Assets	854	1,005
Employee Benefits and Pension Assets	13,244	12,810
Deferred Charges and Other Noncurrent Assets	16,675	20,081
TOTAL OTHER NONCURRENT ASSETS	272,565	263,723
TOTAL ASSETS	$ 2,377,475	$ 2,409,508

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2015 and December 31, 2014
(Unaudited)

	March 31, 2015	December 31, 2014
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 740	$ 45,128
Accounts Payable:		
General	45,166	42,315
Affiliated Companies	24,958	29,259
Long-term Debt Due Within One Year – Nonaffiliated	65,000	65,000
Risk Management Liabilities	2,274	3,256
Customer Deposits	26,325	26,343
Accrued Taxes	16,043	18,873
Accrued Interest	6,142	7,824
Regulatory Liability for Over-Recovered Fuel Costs	—	1,770
Provision for Refund	24,455	31,033
Other Current Liabilities	29,335	38,986
TOTAL CURRENT LIABILITIES	240,438	309,787
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	779,597	754,555
Long-term Risk Management Liabilities	418	423
Deferred Income Taxes	586,116	575,495
Regulatory Liabilities and Deferred Investment Tax Credits	19,300	22,522
Asset Retirement Obligations	64,123	63,479
Employee Benefits and Pension Obligations	12,225	12,531
Deferred Credits and Other Noncurrent Liabilities	6,412	7,073
TOTAL NONCURRENT LIABILITIES	1,468,191	1,436,078
TOTAL LIABILITIES	1,708,629	1,745,865
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER’S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	517,460	517,460
Retained Earnings	103,067	103,069
Accumulated Other Comprehensive Income (Loss)	(2,131)	(7,336)
TOTAL COMMON SHAREHOLDER’S EQUITY	668,846	663,643
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 2,377,475	$ 2,409,508

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2015	2014
OPERATING ACTIVITIES		
Net Income	$ 10,998	$ 32,548
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	24,741	23,522
Deferred Income Taxes	10,561	2,118
Allowance for Equity Funds Used During Construction	(66)	(1,456)
Mark-to-Market of Risk Management Contracts	2,533	(707)
Property Taxes	3,643	3,784
Fuel Over/Under-Recovery, Net	(5,992)	(13,445)
Provision for Refund	(6,578)	—
Change in Other Noncurrent Assets	70	626
Change in Other Noncurrent Liabilities	(1,555)	717
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	12,393	(11,786)
Fuel, Materials and Supplies	21,584	49,679
Accounts Payable	1,836	(505)
Accrued Taxes, Net	(6,859)	10,629
Accrued Interest	(1,682)	(1,038)
Other Current Assets	351	(1,530)
Other Current Liabilities	(8,964)	1,481
Net Cash Flows from Operating Activities	57,014	94,637
INVESTING ACTIVITIES		
Construction Expenditures	(26,169)	(20,979)
Other Investing Activities	231	(853)
Net Cash Flows Used for Investing Activities	(25,938)	(21,832)
FINANCING ACTIVITIES		
Capital Contribution Returned to Parent	—	(100,000)
Issuance of Long-term Debt – Nonaffiliated	24,568	—
Change in Advances from Affiliates, Net	(44,388)	40,840
Principal Payments for Capital Lease Obligations	(292)	(1,208)
Dividends Paid on Common Stock	(11,000)	(15,000)
Other Financing Activities	76	3,064
Net Cash Flows Used for Financing Activities	(31,036)	(72,304)
Net Increase in Cash and Cash Equivalents	40	501
Cash and Cash Equivalents at Beginning of Period	795	743
Cash and Cash Equivalents at End of Period	$ 835	$ 1,244
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 12,465	$ 9,888
Net Cash Paid for Income Taxes	4	—
Noncash Acquisitions Under Capital Leases	120	596
Construction Expenditures Included in Current Liabilities as of March 31,	13,962	15,540

See Condensed Notes to Condensed Financial Statements beginning on page 8.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING MATTERS

General

The 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. Net income for the three months ended March 31, 2015 is not necessarily indicative of results that may be expected for the year ending December 31, 2015. The condensed financial statements are unaudited and should be read in conjunction with the audited 2014 financial statements and notes thereto, which are included in KPCo's 2014 Annual Report.

Management reviewed subsequent events through April 23, 2015, the date that the first quarter 2015 report was issued.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management reviews the new accounting literature to determine its relevance, if any, to KPCo's business. The following final pronouncements will impact the financial statements.

ASU 2014-08 "Presentation of Financial Statements and Property, Plant and Equipment" (ASU 2014-08)

In April 2014, the FASB issued ASU 2014-08 changing the presentation of discontinued operations on the statements of income and other requirements for reporting discontinued operations. Under the new standard, a disposal of a component or a group of components of an entity is required to be reported in discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity's operations and financial results when the component meets the criteria to be classified as held-for-sale or is disposed. The amendments in this update also require additional disclosures about discontinued operations and disposal of an individually significant component of an entity that does not qualify for discontinued operations. This standard must be prospectively applied to all reporting periods presented in financial reports issued after the effective date.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2014. If applicable, this standard will change the presentation of financial statements but will not affect the calculation of net income, comprehensive income or earnings per share. Management adopted ASU 2014-08 effective January 1, 2015. There were no events requiring the application of this new accounting guidance.

ASU 2014-09 "Revenue from Contracts with Customers" (ASU 2014-09)

In May 2014, the FASB issued ASU 2014-09 clarifying the method used to determine the timing and requirements for revenue recognition on the statements of income. Under the new standard, an entity must identify the performance obligations in a contract, the transaction price and allocate the price to specific performance obligations to recognize the revenue when the obligation is completed. The amendments in this update also require disclosure of sufficient information to allow users to understand the nature, amount, timing and uncertainty of revenue and cash flow arising from contracts.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016. Early adoption is not permitted. As applicable, this standard may change the amount of revenue recognized in the income statements in each reporting period. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on revenue or net income. Management plans to adopt ASU 2014-09 effective January 1, 2017.

ASU 2015-01 "Income Statement – Extraordinary and Unusual Items" (ASU 2015-01)

In January 2015, the FASB issued ASU 2015-01 eliminating the concept of extraordinary items for presentation on the face of the income statement. Under the new standard, a material event or transaction that is unusual in nature, infrequent or both shall be reported as a separate component of income from continuing operations. Alternatively, it may be disclosed in the notes to financial statements.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015. Early adoption is permitted if applied from the beginning of a fiscal year. As applicable, this standard may change the presentation of amounts in the income statements. Management plans to adopt ASU 2015-01 effective January 1, 2016.

ASU 2015-03 "Simplifying the Presentation of Debt Issuance Costs" (ASU 2015-03)

In April 2015, the FASB issued ASU 2015-03 to simplify the presentation of debt issuance costs on the balance sheets. Under the new standard, debt issuance costs related to a recognized debt liability will be presented on the balance sheets as a direct deduction from the carrying amount of that debt liability, consistent with discounts. KPCo includes debt issuance costs in Deferred Charges and Other Noncurrent Assets on the balance sheets. Debt issuance costs represent less than 1% of total long-term debt.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015 with early adoption permitted. Management intends to early adopt ASU 2015-03 for the 2015 Annual Report.

ASU 2015-05 "Customer's Accounting for Fees Paid in a Cloud Computing Arrangement" (ASU 2015-05)

In April 2015, the FASB issued ASU 2015-05 to provide guidance to customers about whether a cloud computing arrangement includes a software license. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015 with early adoption permitted. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. Management plans to adopt ASU 2015-05 effective January 1, 2016.

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI for the three months ended March 31, 2015 and 2014. All amounts in the following tables are presented net of related income taxes.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2015

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of December 31, 2014	$ —	$ (161)	$ (7,175)	$ (7,336)
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	—	15	16	31
Net Current Period Other Comprehensive Income	—	15	16	31
Pension and OPEB Adjustment Related to Mitchell Plant	—	—	5,174	5,174
Balance in AOCI as of March 31, 2015	$ —	$ (146)	$ (1,985)	$ (2,131)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2014

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of December 31, 2013	$ 23	$ (222)	$ (5,221)	$ (5,420)
Change in Fair Value Recognized in AOCI	326	—	—	326
Amounts Reclassified from AOCI	(332)	16	117	(199)
Net Current Period Other Comprehensive Income (Loss)	(6)	16	117	127
Pension and OPEB Adjustment Related to Kammer Plant	—	—	(1,308)	(1,308)
Balance in AOCI as of March 31, 2014	$ 17	$ (206)	$ (6,412)	$ (6,601)

Reclassifications from Accumulated Other Comprehensive Income

The following tables provide details of reclassifications from AOCI for the three months ended March 31, 2015 and 2014. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 6 for additional details.

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended March 31, 2015 and 2014

	Amount of (Gain) Loss Reclassified from AOCI	
	Three Months Ended March 31,	
	2015	2014
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Purchased Electricity for Resale	$ —	$ (452)
Other Operation Expense	—	(3)
Maintenance Expense	—	(5)
Property, Plant and Equipment	—	(6)
Regulatory Assets/(Liabilities), Net (a)	—	(43)
Subtotal – Commodity	—	(509)
Interest Rate and Foreign Currency:		
Interest Expense	23	23
Subtotal – Interest Rate and Foreign Currency	23	23
Reclassifications from AOCI, before Income Tax (Expense) Credit	23	(486)
Income Tax (Expense) Credit	8	(170)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	15	(316)
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(10)	(54)
Amortization of Actuarial (Gains)/Losses	35	234
Reclassifications from AOCI, before Income Tax (Expense) Credit	25	180
Income Tax (Expense) Credit	9	63
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	16	117
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ 31	$ (199)

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

4. RATE MATTERS

As discussed in KPCo's 2014 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo's 2014 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 2015 and updates KPCo's 2014 Annual Report.

Regulatory Assets Pending Final Regulatory Approval

Noncurrent Regulatory Assets	March 31, 2015	December 31, 2014
	(in thousands)	
Regulatory Assets Currently Not Earning a Return		
Asset Retirement Obligation	$ 15,406	$ 8,287
Storm Related Costs	12,146	12,146
Total Regulatory Assets Pending Final Regulatory Approval	$ 27,552	$ 20,433

If these costs are ultimately determined not to be recoverable, it could reduce future net income and cash flows and impact financial condition.

Plant Transfer

In October 2013, the KPSC issued an order that approved a modified settlement agreement which included the approval to transfer to KPCo a one-half interest in the Mitchell Plant, comprising 780 MW of average annual generating capacity. In December 2013, the transfer of a one-half interest in the Mitchell Plant to KPCo was completed.

In December 2013, the Attorney General filed an appeal of the order with the Franklin County Circuit Court. In May 2014, KPCo's motion to dismiss the appeal was denied. In May 2014, KPCo filed motions for reconsideration and clarification with the Franklin County Circuit Court. In June 2014, the motion for reconsideration was denied but the motion to clarify was granted, thereby limiting the appeal to the issues of law presented in the Attorney General's appeal. In April 2015, the Franklin County Circuit Court issued an order that affirmed the KPSC's October 2013 order.

Kentucky Fuel Adjustment Clause Review

In August 2014, the KPSC issued an order initiating a review of KPCo's FAC from November 2013 through April 2014. In January 2015, the KPSC issued an order disallowing certain FAC costs during the period of January 2014 through May 2015 while KPCo owns and operates both Big Sandy Plant, Unit 2 and its one-half interest in the Mitchell Plant. As a result of this order, KPCo recorded a regulatory disallowance of $36 million in December 2014. In February 2015, KPCo filed an appeal of this order with the Franklin County Circuit Court. In April 2015, the Franklin County Circuit Court issued an order approving intervenors request to hold this case in abeyance until the KPSC issues a final order in KPCo's two-year FAC review case for the period November 1, 2012 through October 31, 2014.

2014 Kentucky Base Rate Case

In December 2014, KPCo filed a request with the KPSC for a net increase in rates of $70 million, which consists of a $75 million increase in rider rates, offset by a $5 million decrease in annual base rates, to be effective July 2015 based upon a 10.62% return on common equity. The net increase reflects KPCo's ownership interest in the Mitchell Plant, riders to recover the Big Sandy Plant retirement and operational costs and the inclusion of an environmental compliance plan related to the Mitchell Plant FGD. Additionally, the filing included a request to recover deferred storm costs. In March 2015, intervenors filed testimony which recommended net increases in rates ranging from $20 million to $26 million. These increases consist of proposed increases in rider rates ranging from $55 million to $63 million, offset by decreases in annual base rates ranging from $35 million to $37 million and based upon returns on common equity ranging from 8.65% to 8.75%. Intervenor recommendations include the recovery of deferred storm costs. Hearings at the KPSC are scheduled for May 2015. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, KPCo's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements. The Commitments, Guarantees and Contingencies note within KPCo's 2014 Annual Report should be read in conjunction with this report.

GUARANTEES

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

Letter of Credit

KPCo has $65 million of variable rate Pollution Control Bonds supported by a bilateral letter of credit for $66 million. The letter of credit matures in June 2017.

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of March 31, 2015, there were no material liabilities recorded for any indemnifications.

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

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, KPCo is committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance. As of March 31, 2015, the maximum potential loss for these lease agreements was $1.4 million assuming the fair value of the equipment is zero at the end of the lease term.

6. BENEFIT PLANS

KPCo participates in an AEP sponsored qualified pension plan and an unfunded nonqualified pension plan. Substantially all of KPCo's employees are covered by the qualified plan or both the qualified and nonqualified pension plans. KPCo also participates in OPEB plans sponsored by AEP to provide health and life insurance benefits for retired employees.

Components of Net Periodic Benefit Cost

The following table provides the components of KPCo's net periodic benefit cost (credit) for the plans for the three months ended March 31, 2015 and 2014:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2015	2014	2015	2014
	(in thousands)			
Service Cost	$ 670	$ 575	$ 86	$ 118
Interest Cost	1,832	2,010	488	601
Expected Return on Plan Assets	(2,496)	(2,418)	(1,015)	(1,060)
Amortization of Prior Service Cost (Credit)	13	14	(606)	(606)
Amortization of Net Actuarial Loss	946	1,117	155	187
Net Periodic Benefit Cost (Credit)	$ 965	$ 1,298	$ (892)	$ (760)

7. BUSINESS SEGMENTS

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

8. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

KPCo is exposed to certain market risks as a major power producer and marketer of wholesale electricity, natural gas, 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

Risk Management Strategies

The strategy surrounding the use of derivative instruments primarily focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. The risk management strategies also include the use of derivative instruments for trading purposes, focusing on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which AEPSC transacts on behalf of KPCo. To accomplish these objectives, AEPSC, on behalf of KPCo, primarily employs risk management contracts including physical and financial forward purchase-and-sale contracts and, to a lesser extent, OTC swaps and options. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

AEPSC, on behalf of KPCo, enters into power, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline 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. 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 the KPCo's outstanding derivative contracts as of March 31, 2015 and December 31, 2014:

Notional Volume of Derivative Instruments

Primary Risk Exposure	Volume March 31, 2015	Volume December 31, 2014	Unit of Measure
	(in thousands)		
Commodity:			
Power	3,875	6,689	MWhs
Coal	139	233	Tons
Natural Gas	75	87	MMBtus
Heating Oil and Gasoline	190	261	Gallons
Interest Rate	$ 895	$ 1,047	USD

Cash Flow Hedging Strategies

AEPSC, on behalf of KPCo, enters into and designates as cash flow hedges certain derivative transactions for the purchase and sale of power ("Commodity") in order to manage the variable price risk related to forecasted purchases and sales. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and purchases. KPCo does not hedge all commodity price risk.

KPCo's vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of KPCo, enters into financial heating oil and gasoline derivative contracts in order to mitigate price risk of future fuel purchases. Cash flow hedge accounting for these derivative contracts was discontinued effective March 31, 2014. In March 2014, these contracts were grouped as "Commodity" with other risk management activities. KPCo does not hedge all fuel price risk.

AEPSC, on behalf of KPCo, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. AEPSC, on behalf of KPCo, also enters into interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. KPCo does not hedge all interest rate exposure.

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

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

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

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the March 31, 2015 and December 31, 2014 condensed balance sheets, KPCo netted $42 thousand and $67 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $202 thousand and $24 thousand, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following tables represent the gross fair value impact of KPCo's derivative activity on the condensed balance sheets as of March 31, 2015 and December 31, 2014:

Fair Value of Derivative Instruments
March 31, 2015

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets	$ 4,639	$ —	$ —	$ 4,639	$ (1,650)	$ 2,989
Long-term Risk Management Assets	983	—	—	983	(129)	854
Total Assets	5,622	—	—	5,622	(1,779)	3,843
Current Risk Management Liabilities	4,068	—	—	4,068	(1,794)	2,274
Long-term Risk Management Liabilities	563	—	—	563	(145)	418
Total Liabilities	4,631	—	—	4,631	(1,939)	2,692
Total MTM Derivative Contract Net Assets (Liabilities)	$ 991	$ —	$ —	$ 991	$ 160	$ 1,151

Fair Value of Derivative Instruments
December 31, 2014

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets	$ 8,631	$ —	$ —	$ 8,631	$ (2,273)	$ 6,358
Long-term Risk Management Assets	1,060	—	—	1,060	(55)	1,005
Total Assets	9,691	—	—	9,691	(2,328)	7,363
Current Risk Management Liabilities	5,487	—	—	5,487	(2,231)	3,256
Long-term Risk Management Liabilities	477	—	—	477	(54)	423
Total Liabilities	5,964	—	—	5,964	(2,285)	3,679
Total MTM Derivative Contract Net Assets (Liabilities)	$ 3,727	$ —	$ —	$ 3,727	$ (43)	$ 3,684

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the condensed balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."
(c) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

The table below presents KPCo's activity of derivative risk management contracts for the three months ended March 31, 2015 and 2014:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended March 31, 2015 and 2014

Location of Gain (Loss)	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014
	(in thousands)	
Electric Generation, Transmission and Distribution Revenues	$ 1,555	$ 6,940
Other Operation Expense	(31)	—
Maintenance Expense	(42)	—
Purchased Electricity for Resale	2,254	—
Fuel and Other Consumables Used for Electric Generation	(9)	1
Regulatory Assets (a)	(240)	—
Regulatory Liabilities (a)	(3,358)	1,120
Total Gain on Risk Management Contracts	$ 129	$ 8,061

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

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

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

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on KPCo's condensed statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on KPCo's condensed statements of income depending on the relevant facts and circumstances. Certain derivatives that economically hedge future commodity risk are recorded in the same expense line item on the condensed statements of income as that of the associated risk. However, unrealized and some realized gains and losses for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains), in accordance with the accounting guidance for "Regulated Operations."

Accounting for 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).

Realized gains and losses on derivative contracts for the purchase and sale of power designated as cash flow hedges are included in Revenues or Purchased Electricity for Resale on KPCo's condensed statements of income, or in Regulatory Assets or Regulatory Liabilities on KPCo's condensed balance sheets, depending on the specific nature of the risk being hedged. During the three months ended March 31, 2015, KPCo did not designate power derivatives as cash flow hedges. During the three months ended March 31, 2014, KPCo designated power derivatives as cash flow hedges.

KPCo reclassifies gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on its condensed balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the condensed statements of income. Cash flow hedge accounting for these derivative contracts was immaterial and was discontinued effective March 31, 2014.

KPCo reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on its condensed balance sheets into Interest Expense on its condensed statements of income in those periods in which hedged interest payments occur. During the three months ended March 31, 2015 and 2014, KPCo did not designate any interest rate derivatives as cash flow hedges.

During the three months ended March 31, 2015 and 2014, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

For details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's condensed balance sheets and the reasons for changes in cash flow hedges for the three months ended March 31, 2015 and 2014, see Note 3.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's condensed balance sheets as of March 31, 2015 and December 31, 2014 were:

Impact of Cash Flow Hedges on the Condensed Balance Sheet
March 31, 2015

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ —	$ —	$ —
Hedging Liabilities (a)	—	—	—
AOCI Loss Net of Tax	—	(146)	(146)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	—	(60)	(60)

Impact of Cash Flow Hedges on the Condensed Balance Sheet
December 31, 2014

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ —	$ —	$ —
Hedging Liabilities (a)	—	—	—
AOCI Gain (Loss) Net of Tax	—	(161)	(161)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	—	(60)	(60)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on KPCo's condensed balance sheets.

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of March 31, 2015, KPCo is not hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") its exposure to variability in future cash flows related to forecasted transactions.

Credit Risk

AEPSC, on behalf of KPCo, limits credit risk in KPCo's wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. AEPSC, on behalf of KPCo, uses Moody's, Standard and Poor's and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

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

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, KPCo is obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. KPCo has not experienced a downgrade below investment grade. The following table represents KPCo's exposure if credit ratings were to decline below a specified rating threshold as of March 31, 2015 and December 31, 2014:

	March 31, 2015	December 31, 2014
	(in thousands)	
Fair Value of Contracts with Credit Downgrade Triggers	$ —	$ —
Amount of Collateral KPCo Would Have been Required to Post for Derivative Contracts as well as Derivative and Non-Derivative Contracts Subject to the Same Master Netting Arrangement	—	—
Amount of Collateral KPCo Would Have Been Required to Post Attributable to RTOs and ISOs	935	1,303
Amount of Collateral Attributable to Other Contracts	16	14

In addition, a majority of KPCo's non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation in excess of $50 million. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted by KPCo and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering KPCo's contractual netting arrangements as of March 31, 2015 and December 31, 2014:

	March 31, 2015	December 31, 2014
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 1,655	$ 1,859
Amount of Cash Collateral Posted	—	—
Additional Settlement Liability if Cross Default Provision is Triggered	1,628	1,852

9. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability. The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with established risk management policies as approved by the Finance Committee of AEP's Board of Directors. The AEP System's market risk oversight staff independently monitors the risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (Regulated Risk Committee) various daily and quarterly reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations and Chief Risk Officer.

For commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are nonbinding in nature, but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of the contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A significant portion of the Level 3 instruments have been economically hedged which greatly limits potential earnings volatility.

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of KPCo's Long-term Debt as of March 31, 2015 and December 31, 2014 are summarized in the following table:

	March 31, 2015		December 31, 2014	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 844,597	$ 989,387	$ 819,555	$ 948,967

Fair Value Measurements of Financial Assets and Liabilities

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, 2015 and December 31, 2014. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2015

	Level 1	Level 2	Level 3	Other	Total
Assets:		(in thousands)			
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 46	$ 3,449	$ 2,049	$ (1,701)	$ 3,843
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 50	$ 4,124	$ 379	$ (1,861)	$ 2,692

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2014

	Level 1	Level 2	Level 3	Other	Total
Assets:		(in thousands)			
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 42	$ 5,328	$ 4,320	$ (2,327)	$ 7,363
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 47	$ 5,523	$ 393	$ (2,284)	$ 3,679

(a) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(b) Substantially comprised of power contracts.

There were no transfers between Level 1 and Level 2 during the three months ended March 31, 2015 and 2014.

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

Three Months Ended March 31, 2015	**Net Risk Management Assets (Liabilities)**
	(in thousands)
Balance as of December 31, 2014	$ 3,927
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	467
Purchases, Issuances and Settlements (c)	(2,791)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	67
Balance as of March 31, 2015	$ 1,670

Three Months Ended March 31, 2014	**Net Risk Management Assets (Liabilities)**
	(in thousands)
Balance as of December 31, 2013	$ 2,171
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	5,374
Purchases, Issuances and Settlements (c)	(5,913)
Transfers into Level 3 (d) (e)	(786)
Transfers out of Level 3 (e) (f)	(1)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	605
Balance as of March 31, 2014	$ 1,450

(a) Included in revenues on KPCo’s condensed statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Represents the settlement of risk management commodity contracts for the reporting period.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(f) Represents existing assets or liabilities that were previously categorized as Level 3.
(g) 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.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions as of March 31, 2015 and December 31, 2014:

Significant Unobservable Inputs
March 31, 2015

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input (a)	Forward Price Range Low	Forward Price Range High	Forward Price Range Weighted Average
	(in thousands)						
Energy Contracts	$ 1,648	$ 338	Discounted Cash Flow	Forward Market Price	$ 10.55	$ 51.25	$ 36.89
FTRs	401	41	Discounted Cash Flow	Forward Market Price	(9.62)	6.77	0.62
Total	$ 2,049	$ 379					

Significant Unobservable Inputs
December 31, 2014

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input (a)	Forward Price Range Low	Forward Price Range High	Forward Price Range Weighted Average
	(in thousands)						
Energy Contracts	$ 2,088	$ 370	Discounted Cash Flow	Forward Market Price	$ 13.43	$ 123.02	$ 52.47
FTRs	2,232	23	Discounted Cash Flow	Forward Market Price	(14.63)	20.02	1.01
Total	$ 4,320	$ 393					

(a) Represents market prices in dollars per MWh.

The following table provides sensitivity of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts and FTRs as of March 31, 2015:

Sensitivity of Fair Value Measurements
March 31, 2015

Significant Unobservable Input	Position	Change in Input	Impact on Fair Value Measurement
Forward Market Price	Buy	Increase (Decrease)	Higher (Lower)
Forward Market Price	Sell	Increase (Decrease)	Lower (Higher)

10. INCOME TAXES

AEP System Tax Allocation Agreement

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

Federal and State Income Tax Audit Status

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2011. The IRS examination of years 2011, 2012 and 2013 started in April 2014. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to materially impact net income.

KPCo and other AEP subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns. KPCo and other AEP subsidiaries are currently under examination in several state and local jurisdictions. However, it is possible that previously filed tax returns have positions that may be challenged by these tax authorities. Management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income. KPCo is no longer subject to state or local income tax examinations by tax authorities for years before 2009.

11. FINANCING ACTIVITIES

Long-term Debt

Long-term debt issued during the first three months of 2015 is shown in the table below:

Type of Debt	Principal Amount (a)	Interest Rate	Due Date
	(in thousands)	(%)	
Other Long-term Debt	$ 25,000	Variable	2018

(a) Amount indicated on the statement of cash flows is net of issuance costs and premium or discount and will not tie to the issuance amount.

Dividend Restrictions

KPCo pays dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of KPCo to transfer funds to Parent in the form of dividends.

Federal Power Act

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

Leverage Restrictions

Pursuant to the credit agreement leverage restrictions, KPCo must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%.

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding loans to (borrowings from) the Utility Money Pool as of March 31, 2015 and December 31, 2014 are included in Advances to Affiliates and Advances from Affiliates, respectively, on KPCo's condensed balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the three months ended March 31, 2015 are described in the following table:

Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Borrowings from the Utility Money Pool as of March 31, 2015	Authorized Short-Term Borrowing Limit
		(in thousands)			
$ 52,477	$ —	$ 29,409	$ —	$ 740	$ 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, 2015 and 2014 are summarized in the following table:

Three Months Ended March 31,	Maximum Interest Rate for Funds Borrowed from the Utility Money Pool	Minimum Interest Rate for Funds Borrowed from the Utility Money Pool	Maximum Interest Rate for Funds Loaned to the Utility Money Pool	Minimum Interest Rate 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
2015	0.59%	0.39%	—%	—%	0.47%	—%
2014	0.33%	0.28%	0.33%	0.28%	0.31%	0.32%

Sale of Receivables – AEP Credit

Under a sale of receivables arrangement, KPCo sells, without recourse, certain of its customer accounts receivable and accrued unbilled revenue balances to AEP Credit and is charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for KPCo's receivables. The costs of customer accounts receivable sold are reported in Other Operation expense on KPCo's condensed statements of income. KPCo manages and services its accounts receivable sold.

AEP Credit's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables. The agreement was increased in June 2014 from $700 million and expires in June 2016.

KPCo's amounts of accounts receivable and accrued unbilled revenues sold under the sale of receivables agreement were $46 million and $46 million as of March 31, 2015 and December 31, 2014, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold for the three months ended March 31, 2015 and 2014 were $840 thousand and $763 thousand, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit for the three months ended March 31, 2015 and 2014 were $155 million and $179 million, respectively.

12. VARIABLE INTEREST ENTITIES

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether KPCo is the primary beneficiary of a VIE, management considers factors such as equity at risk, the amount of the VIE's variability KPCo absorbs, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE, variable interests held by related parties and other factors. Management believes that significant assumptions and judgments were applied consistently. KPCo is not the primary beneficiary of any VIE and has not provided financial or other support to any VIE that was not previously contractually required.

AEPSC provides certain managerial and professional services to AEP's subsidiaries. AEP is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. KPCo's total billings from AEPSC for the three months ended March 31, 2015 and 2014 were $13 million and $13 million, respectively. The carrying amount of liabilities associated with AEPSC as of March 31, 2015 and December 31, 2014 was $5 million and $8 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant, Unit 1 and leases a 50% interest in Rockport Plant, Unit 2. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP has agreed to provide AEGCo with the funds necessary to satisfy all of the debt obligations of AEGCo. KPCo is considered to have a significant interest in AEGCo due to these transactions. KPCo is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. Due to AEP management's control over AEGCo, KPCo is not considered the primary beneficiary of AEGCo. In the event AEGCo would require financing or other support outside the billings to KPCo, this financing would be provided by AEP. Total billings from AEGCo for the three months ended March 31, 2015 and 2014 were $24 million and $30 million, respectively. The carrying amount of liabilities associated with AEGCo as of March 31, 2015 and December 31, 2014 was $7 million and $9 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

13. PROPERTY, PLANT AND EQUIPMENT

Coal Combustion Residual Rule

In 2010, the Federal EPA published a proposed rule to regulate the disposal and beneficial re-use of coal combustion residuals, including fly ash and bottom ash generated at coal-fired electric generating units and also flue gas desulfurization gypsum generated at some coal-fired plants. The final rule was published in the Federal Register in April 2015 and becomes effective six months after publication. Management is in the process of evaluating the impact of this rule and has not yet determined an estimate of the expected increase in asset retirement obligations. Upon completion of the evaluation, management expects to record an increase in asset retirement obligations in the second quarter of 2015 due to this publication.

14. DISPOSITION PLANT SEVERANCE

Management intends to retire several generation plants or units of plants during 2015. The plant closures will result in involuntary severances. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

The disposition plant severance activity for the three months ended March 31, 2015 is described in the following table:

Balance as of December 31, 2014	Expense Allocation from AEPSC	Incurred	Settled	Adjustments	Remaining Balance as of March 31, 2015
		(in thousands)			
$ 4,539	$ (1)	$ 60	$ 1 (a)	$ —	$ 4,599

(a) Settled includes amounts received from affiliates for expenses related to intercompany billing for operation and maintenance of affiliate plant.

KPCo recorded a charge of $4 million to Other Operation expense in December 2014 related to employees at the disposition plants. These expenses, net of adjustments, relate primarily to severance benefits and are included primarily in Other Operation expense on the condensed statements of income. The remaining liability is included in Other Current Liabilities on the condensed balance sheets. Management does not expect additional severance costs to be incurred related to this initiative.

Kentucky Power Company

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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., an electric utility holding company.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AOCI	Accumulated Other Comprehensive Income.
ASU	Accounting Standards Update.
FASB	Financial Accounting Standards Board.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
PJM	Pennsylvania - New Jersey - Maryland regional transmission organization.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SIA	System Integration Agreement, effective June 15, 2000, as amended, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
REVENUES				
Electric Generation, Transmission and Distribution	$ 148,503	$ 205,104	$ 348,403	$ 432,735
Sales to AEP Affiliates	2,577	1,275	3,934	6,690
Other Revenues	196	184	388	268
TOTAL REVENUES	151,276	206,563	352,725	439,693
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	37,586	79,606	106,785	151,968
Purchased Electricity for Resale	6,165	2,057	17,961	5,170
Purchased Electricity from AEP Affiliates	25,711	27,938	49,268	59,360
Other Operation	19,749	18,940	40,080	38,805
Maintenance	18,896	17,724	37,185	36,366
Depreciation and Amortization	23,508	23,033	48,249	46,555
Taxes Other Than Income Taxes	5,395	5,287	10,999	10,590
TOTAL EXPENSES	137,010	174,585	310,527	348,814
OPERATING INCOME	14,266	31,978	42,198	90,879
Other Income (Expense):				
Interest Income	93	47	112	80
Allowance for Equity Funds Used During Construction	388	1,260	454	2,716
Interest Expense	(11,183)	(9,241)	(22,220)	(18,342)
INCOME BEFORE INCOME TAX EXPENSE	3,564	24,044	20,544	75,333
Income Tax Expense	1,256	8,786	7,238	27,527
NET INCOME	$ 2,308	$ 15,258	$ 13,306	$ 47,806

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

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Net Income	$ 2,308	$ 15,258	$ 13,306	$ 47,806
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $8 and $1 for the Three Months Ended June 30, 2015 and 2014, Respectively, and $16 and $4 for the Six Months Ended June 30, 2015 and 2014, Respectively	15	(2)	30	8
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $9 and $62 for the Three Months Ended June 30, 2015 and 2014, Respectively, and $18 and $125 for the Six Months Ended June 30, 2015 and 2014, Respectively	17	116	33	233
TOTAL OTHER COMPREHENSIVE INCOME	32	114	63	241
TOTAL COMPREHENSIVE INCOME	$ 2,340	$ 15,372	$ 13,369	$ 48,047

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 30, 2015 and 2014
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2013	$ 50,450	$ 614,648	$ 179,691	$ (5,420)	$ 839,369
Capital Contribution Returned to Parent		(100,000)			(100,000)
Common Stock Dividends			(30,000)		(30,000)
Other Changes in Common Shareholder's Equity		2,812			2,812
Net Income			47,806		47,806
Other Comprehensive Income				241	241
Pension and OPEB Adjustment Related to Kammer Plant				(1,308)	(1,308)
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2014	$ 50,450	$ 517,460	$ 197,497	$ (6,487)	$ 758,920
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2014	$ 50,450	$ 517,460	$ 103,069	$ (7,336)	$ 663,643
Common Stock Dividends			(22,000)		(22,000)
Net Income			13,306		13,306
Other Comprehensive Income				63	63
Pension and OPEB Adjustment Related to Mitchell Plant				5,174	5,174
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2015	$ 50,450	$ 517,460	$ 94,375	$ (2,099)	$ 660,186

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
June 30, 2015 and December 31, 2014
(in thousands)
(Unaudited)

	June 30, 2015	December 31, 2014
CURRENT ASSETS		
Cash and Cash Equivalents	$ 515	$ 795
Accounts Receivable:		
Customers	13,711	21,125
Affiliated Companies	20,270	30,436
Accrued Unbilled Revenues	3,108	2,047
Miscellaneous	206	131
Allowance for Uncollectible Accounts	(186)	(87)
Total Accounts Receivable	37,109	53,652
Fuel	21,355	45,256
Materials and Supplies	27,632	34,499
Risk Management Assets	7,068	6,358
Deferred Income Tax Benefits	6,504	8,899
Accrued Tax Benefits	46,537	10,944
Regulatory Asset for Under-Recovered Fuel Costs	2,207	—
Prepayments and Other Current Assets	4,245	4,301
TOTAL CURRENT ASSETS	153,172	164,704
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,182,389	1,161,100
Transmission	558,718	558,099
Distribution	742,369	727,569
Other Property, Plant and Equipment (December 31, 2014 Amount Includes 2015 Plant Retirement)	65,937	521,327
Construction Work in Progress	63,095	39,194
Total Property, Plant and Equipment	2,612,508	3,007,289
Accumulated Depreciation and Amortization	877,465	1,026,208
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,735,043	1,981,081
OTHER NONCURRENT ASSETS		
Regulatory Assets	498,369	229,827
Long-term Risk Management Assets	619	1,005
Employee Benefits and Pension Assets	13,685	12,810
Deferred Charges and Other Noncurrent Assets	12,973	20,081
TOTAL OTHER NONCURRENT ASSETS	525,646	263,723
TOTAL ASSETS	$ 2,413,861	$ 2,409,508

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
June 30, 2015 and December 31, 2014
(Unaudited)

	June 30, 2015	December 31, 2014
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 27,176	$ 45,128
Accounts Payable:		
General	31,304	42,315
Affiliated Companies	26,749	29,259
Long-term Debt Due Within One Year – Nonaffiliated	65,000	65,000
Risk Management Liabilities	2,647	3,256
Customer Deposits	26,745	26,343
Accrued Taxes	15,767	18,873
Accrued Interest	7,816	7,824
Regulatory Liability for Over-Recovered Fuel Costs	—	1,770
Provision for Refund	17,878	31,033
Other Current Liabilities	36,784	38,986
TOTAL CURRENT LIABILITIES	257,866	309,787
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	779,639	754,555
Long-term Risk Management Liabilities	298	423
Deferred Income Taxes	625,215	575,495
Regulatory Liabilities and Deferred Investment Tax Credits	4,326	22,522
Asset Retirement Obligations	69,872	63,479
Employee Benefits and Pension Obligations	10,379	12,531
Deferred Credits and Other Noncurrent Liabilities	6,080	7,073
TOTAL NONCURRENT LIABILITIES	1,495,809	1,436,078
TOTAL LIABILITIES	1,753,675	1,745,865
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	517,460	517,460
Retained Earnings	94,375	103,069
Accumulated Other Comprehensive Income (Loss)	(2,099)	(7,336)
TOTAL COMMON SHAREHOLDER'S EQUITY	660,186	663,643
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 2,413,861	$ 2,409,508

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2015 and 2014
(in thousands)
(Unaudited)

	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
OPERATING ACTIVITIES		
Net Income	$ 13,306	$ 47,806
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	48,249	46,555
Deferred Income Taxes	43,286	(1,571)
Allowance for Equity Funds Used During Construction	(454)	(2,716)
Mark-to-Market of Risk Management Contracts	(1,059)	(1,482)
Pension Contributions to Qualified Plan Trust	(1,900)	(1,923)
Property Taxes	7,164	7,076
Fuel Over/Under-Recovery, Net	(3,977)	(13,026)
Provision for Refund	(13,155)	—
Change in Other Noncurrent Assets	(6,592)	1,203
Change in Other Noncurrent Liabilities	2,275	2,592
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	16,543	(20,280)
Fuel, Materials and Supplies	26,667	72,812
Accounts Payable	(7,872)	9,211
Accrued Taxes, Net	(38,699)	17,089
Other Current Assets	638	(426)
Other Current Liabilities	(9,815)	3,130
Net Cash Flows from Operating Activities	74,605	166,050
INVESTING ACTIVITIES		
Construction Expenditures	(59,866)	(44,812)
Change in Advances to Affiliates, Net	—	(49,348)
Other Investing Activities	861	(616)
Net Cash Flows Used for Investing Activities	(59,005)	(94,776)
FINANCING ACTIVITIES		
Capital Contribution Returned to Parent	—	(100,000)
Issuance of Long-term Debt – Nonaffiliated	24,546	64,780
Change in Advances from Affiliates, Net	(17,952)	(8,564)
Principal Payments for Capital Lease Obligations	(550)	(1,489)
Dividends Paid on Common Stock	(22,000)	(30,000)
Other Financing Activities	76	4,084
Net Cash Flows Used for Financing Activities	(15,880)	(71,189)
Net Increase (Decrease) in Cash and Cash Equivalents	(280)	85
Cash and Cash Equivalents at Beginning of Period	795	743
Cash and Cash Equivalents at End of Period	$ 515	$ 828
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 21,718	$ 17,891
Net Cash Paid for Income Taxes	106	5,788
Noncash Acquisitions Under Capital Leases	132	1,252
Construction Expenditures Included in Current Liabilities as of June 30,	11,081	20,184

See Condensed Notes to Condensed Financial Statements beginning on page 8.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING MATTERS

General

The 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. Net income for the three and six months ended June 30, 2015 is not necessarily indicative of results that may be expected for the year ending December 31, 2015. The condensed financial statements are unaudited and should be read in conjunction with the audited 2014 financial statements and notes thereto, which are included in KPCo's 2014 Annual Report.

Management reviewed subsequent events through July 23, 2015, the date that the second quarter 2015 report was issued.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management reviews the new accounting literature to determine its relevance, if any, to KPCo's business. The following final pronouncements will impact the financial statements.

ASU 2014-08 "Presentation of Financial Statements and Property, Plant and Equipment" (ASU 2014-08)

In April 2014, the FASB issued ASU 2014-08 changing the presentation of discontinued operations on the statements of income and other requirements for reporting discontinued operations. Under the new standard, a disposal of a component or a group of components of an entity is required to be reported in discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity's operations and financial results when the component meets the criteria to be classified as held-for-sale or is disposed. The amendments in this update also require additional disclosures about discontinued operations and disposal of an individually significant component of an entity that does not qualify for discontinued operations. This standard must be prospectively applied to all reporting periods presented in financial reports issued after the effective date.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2014. If applicable, this standard will change the presentation of financial statements but will not affect the calculation of net income, comprehensive income or earnings per share. Management adopted ASU 2014-08 effective January 1, 2015. There were no events requiring the application of this new accounting guidance.

ASU 2014-09 "Revenue from Contracts with Customers" (ASU 2014-09)

In May 2014, the FASB issued ASU 2014-09 clarifying the method used to determine the timing and requirements for revenue recognition on the statements of income. Under the new standard, an entity must identify the performance obligations in a contract, the transaction price and allocate the price to specific performance obligations to recognize the revenue when the obligation is completed. The amendments in this update also require disclosure of sufficient information to allow users to understand the nature, amount, timing and uncertainty of revenue and cash flow arising from contracts.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016. Early adoption is not permitted. As applicable, this standard may change the amount of revenue recognized in the income statements in each reporting period. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on revenue or net income. Management plans to adopt ASU 2014-09 effective January 1, 2017.

ASU 2015-01 "Income Statement – Extraordinary and Unusual Items" (ASU 2015-01)

In January 2015, the FASB issued ASU 2015-01 eliminating the concept of extraordinary items for presentation on the face of the income statement. Under the new standard, a material event or transaction that is unusual in nature, infrequent or both shall be reported as a separate component of income from continuing operations. Alternatively, it may be disclosed in the notes to financial statements.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015. Early adoption is permitted if applied from the beginning of a fiscal year. As applicable, this standard may change the presentation of amounts in the income statements. Management plans to adopt ASU 2015-01 effective January 1, 2016.

ASU 2015-03 "Simplifying the Presentation of Debt Issuance Costs" (ASU 2015-03)

In April 2015, the FASB issued ASU 2015-03 to simplify the presentation of debt issuance costs on the balance sheets. Under the new standard, debt issuance costs related to a recognized debt liability will be presented on the balance sheets as a direct deduction from the carrying amount of that debt liability, consistent with discounts. KPCo includes debt issuance costs in Deferred Charges and Other Noncurrent Assets on the condensed balance sheets. Debt issuance costs represent less than 1% of total long-term debt.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015 with early adoption permitted. Management intends to early adopt ASU 2015-03 for the 2015 Annual Report.

ASU 2015-05 "Customer's Accounting for Fees Paid in a Cloud Computing Arrangement" (ASU 2015-05)

In April 2015, the FASB issued ASU 2015-05 to provide guidance to customers about whether a cloud computing arrangement includes a software license. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015 with early adoption permitted. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. Management plans to adopt ASU 2015-05 effective January 1, 2016.

ASU 2015-11 "Simplifying the Measurement of Inventory" (ASU 2015-11)

In July 2015, the FASB issued ASU 2015-11 to simplify the guidance on the subsequent measurement of inventory, excluding inventory measured using last-in, first out or the retail inventory method. Under the new standard, inventory should be at the lower of cost and net realizable value. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016 with early adoption permitted. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. Management plans to adopt ASU 2015-11 effective January 1, 2017.

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI for the three and six months ended June 30, 2015 and 2014. All amounts in the following tables are presented net of related income taxes.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended June 30, 2015

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
		(in thousands)		
Balance in AOCI as of March 31, 2015	$ —	$ (146)	$ (1,985)	$ (2,131)
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	—	15	17	32
Net Current Period Other Comprehensive Income	—	15	17	32
Balance in AOCI as of June 30, 2015	$ —	$ (131)	$ (1,968)	$ (2,099)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended June 30, 2014

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
		(in thousands)		
Balance in AOCI as of March 31, 2014	$ 17	$ (206)	$ (6,412)	$ (6,601)
Change in Fair Value Recognized in AOCI	22	—	—	22
Amounts Reclassified from AOCI	(39)	15	116	92
Net Current Period Other Comprehensive Income (Loss)	(17)	15	116	114
Balance in AOCI as of June 30, 2014	$ —	$ (191)	$ (6,296)	$ (6,487)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Six Months Ended June 30, 2015

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
		(in thousands)		
Balance in AOCI as of December 31, 2014	$ —	$ (161)	$ (7,175)	$ (7,336)
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	—	30	33	63
Net Current Period Other Comprehensive Income	—	30	33	63
Pension and OPEB Adjustment Related to Mitchell Plant	—	—	5,174	5,174
Balance in AOCI as of June 30, 2015	$ —	$ (131)	$ (1,968)	$ (2,099)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Six Months Ended June 30, 2014

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
		(in thousands)		
Balance in AOCI as of December 31, 2013	$ 23	$ (222)	$ (5,221)	$ (5,420)
Change in Fair Value Recognized in AOCI	348	—	—	348
Amounts Reclassified from AOCI	(371)	31	233	(107)
Net Current Period Other Comprehensive Income (Loss)	(23)	31	233	241
Pension and OPEB Adjustment Related to Kammer Plant	—	—	(1,308)	(1,308)
Balance in AOCI as of June 30, 2014	$ —	$ (191)	$ (6,296)	$ (6,487)

Reclassifications from Accumulated Other Comprehensive Income

The following tables provide details of reclassifications from AOCI for the three and six months ended June 30, 2015 and 2014. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 6 for additional details.

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended June 30, 2015 and 2014

	Amount of (Gain) Loss Reclassified from AOCI	
	Three Months Ended June 30,	
	2015	2014
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Purchased Electricity for Resale	$ —	$ (60)
Subtotal – Commodity	—	(60)
Interest Rate and Foreign Currency:		
Interest Expense	23	23
Subtotal – Interest Rate and Foreign Currency	23	23
Reclassifications from AOCI, before Income Tax (Expense) Credit	23	(37)
Income Tax (Expense) Credit	8	(13)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	15	(24)
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(10)	(53)
Amortization of Actuarial (Gains)/Losses	36	232
Reclassifications from AOCI, before Income Tax (Expense) Credit	26	179
Income Tax (Expense) Credit	9	63
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	17	116
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ 32	$ 92

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Six Months Ended June 30, 2015 and 2014

	Amount of (Gain) Loss Reclassified from AOCI Six Months Ended June 30, 2015	2014
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Purchased Electricity for Resale	$ —	$ (512)
Other Operation Expense	—	(3)
Maintenance Expense	—	(5)
Property, Plant and Equipment	—	(6)
Regulatory Assets/(Liabilities), Net (a)	—	(43)
Subtotal – Commodity	—	(569)
Interest Rate and Foreign Currency:		
Interest Expense	46	46
Subtotal – Interest Rate and Foreign Currency	46	46
Reclassifications from AOCI, before Income Tax (Expense) Credit	46	(523)
Income Tax (Expense) Credit	16	(183)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	30	(340)
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(20)	(107)
Amortization of Actuarial (Gains)/Losses	71	466
Reclassifications from AOCI, before Income Tax (Expense) Credit	51	359
Income Tax (Expense) Credit	18	126
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	33	233
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ 63	$ (107)

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

4. RATE MATTERS

As discussed in KPCo's 2014 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo's 2014 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 2015 and updates KPCo's 2014 Annual Report.

Regulatory Assets Pending Final Regulatory Approval

Noncurrent Regulatory Assets	June 30, 2015	December 31, 2014
	(in thousands)	
Regulatory Assets Currently Not Earning a Return		
Storm Related Costs	$ —	$ 12,146
Asset Retirement Obligation	—	8,287
Total Regulatory Assets Pending Final Regulatory Approval	$ —	$ 20,433

If these costs are ultimately determined not to be recoverable, it could reduce future net income and cash flows and impact financial condition.

Plant Transfer

In October 2013, the KPSC issued an order that approved a modified settlement agreement which included the approval to transfer to KPCo a one-half interest in the Mitchell Plant, comprising 780 MW of average annual generating capacity. In December 2013, the transfer of a one-half interest in the Mitchell Plant to KPCo was completed. In December 2013, the Attorney General filed an appeal of the order with the Franklin County Circuit Court. In April 2015, the Franklin County Circuit Court issued an order that affirmed the KPSC's October 2013 order. In May 2015, the Attorney General filed an appeal of the April 2015 Franklin County Circuit Court order that had affirmed the KPSC's order.

Consistent with KPCo's December 2012 plant transfer filing with the KPSC, Big Sandy Plant, Unit 2 was retired in May 2015. Upon retirement, $194 million was reclassified as Regulatory Assets on the condensed balance sheet related to the net book value of Big Sandy Plant, Unit 2 and the related asset retirement obligations, costs of removal and materials and supplies. These regulatory assets will be amortized over 25 years, effective July 2015.

Kentucky Fuel Adjustment Clause Review

In August 2014, the KPSC issued an order initiating a review of KPCo's FAC from November 2013 through April 2014. In January 2015, the KPSC issued an order disallowing certain FAC costs during the period of January 2014 through May 2015 while KPCo owned and operated both Big Sandy Plant, Unit 2 and its one-half interest in the Mitchell Plant. As a result of this order, KPCo recorded a regulatory disallowance of $36 million in December 2014. In February 2015, KPCo filed an appeal of this order with the Franklin County Circuit Court. In April 2015, the Franklin County Circuit Court issued an order approving intervenors' requests to hold this case in abeyance until the KPSC issues a final order in KPCo's two-year FAC review case for the period November 2012 through October 2014.

2014 Kentucky Base Rate Case

In December 2014, KPCo filed a request with the KPSC for a net increase in rates of $70 million, which consists of a $75 million increase in rider rates, offset by a $5 million decrease in annual base rates, to be effective July 2015 based upon a 10.62% return on common equity. The net increase reflects KPCo's ownership interest in the Mitchell Plant, riders to recover the Big Sandy Plant retirement and operational costs and the inclusion of an environmental compliance plan related to the Mitchell Plant FGD. Additionally, the filing included a request to recover deferred storm costs. In March 2015, intervenors filed testimony which recommended net increases in rates ranging from $20 million to $26 million. These increases consisted of proposed increases in rider rates ranging from $55 million to $63 million, offset by decreases in annual base rates ranging from $35 million to $37 million and based upon returns on common equity ranging from 8.65% to 8.75%. Intervenor recommendations included the recovery of deferred storm costs.

In April 2015, a non-unanimous stipulation agreement between KPCo and certain intervenors was filed with the KPSC. The parties to the stipulation recommended a net revenue increase of $45 million, which consisted of a $68 million increase in rider rates, offset by a $23 million decrease in annual base rates, to be effective July 2015. The proposed net increase reflects KPCo's ownership interest in the Mitchell Plant, riders to recover the Big Sandy Plant retirement and operational costs and the inclusion of an environmental compliance plan. Additionally, the agreement included (a) recovery of $12 million of deferred storm costs, (b) any difference between the actual off-system sales margins and the $15 million included in the proposed annual base rates to be shared with 75% to the customer and 25% to KPCo and (c) dismissal of the KPCo and the Kentucky Industrial Utility Customers appeals of the KPSC order in the KPCo fuel adjustment clause review for November 2012 through October 2014.

In June 2015, the KPSC issued an order that approved a modified stipulation agreement. The order approved a net revenue increase of $45 million, as proposed in the stipulation agreement, and contained modifications that included (a) approval to recover $2 million of IGCC and certain carbon capture study costs, both over 25 years, (b) no deferral of certain PJM costs and (c) denial of the recovery of certain potential purchased power costs through a rider. Once this order becomes final and non-appealable, KPCo will withdraw its appeal of the KPSC order in the KPCo fuel adjustment clause review. See "Kentucky Fuel Adjustment Clause Review" section above.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, KPCo's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements. The Commitments, Guarantees and Contingencies note within KPCo's 2014 Annual Report should be read in conjunction with this report.

GUARANTEES

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

Letter of Credit

KPCo has $65 million of variable rate Pollution Control Bonds supported by a bilateral letter of credit for $66 million. The letter of credit matures in June 2017.

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of June 30, 2015, there were no material liabilities recorded for any indemnifications.

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

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, KPCo is committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance. As of June 30, 2015, the maximum potential loss for these lease agreements was $1.5 million assuming the fair value of the equipment is zero at the end of the lease term.

6. BENEFIT PLANS

KPCo participates in an AEP sponsored qualified pension plan and an unfunded nonqualified pension plan. Substantially all of KPCo's employees are covered by the qualified plan or both the qualified and nonqualified pension plans. KPCo also participates in OPEB plans sponsored by AEP to provide health and life insurance benefits for retired employees.

Components of Net Periodic Benefit Cost

The following tables provide the components of KPCo's net periodic benefit cost (credit) for the plans for the three and six months ended June 30, 2015 and 2014:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands)			
Service Cost	$ 670	$ 575	$ 86	$ 118
Interest Cost	1,831	2,011	488	601
Expected Return on Plan Assets	(2,495)	(2,419)	(1,015)	(1,059)
Amortization of Prior Service Cost (Credit)	13	14	(606)	(606)
Amortization of Net Actuarial Loss	947	1,116	156	186
Net Periodic Benefit Cost (Credit)	$ 966	$ 1,297	$ (891)	$ (760)

	Pension Plans		Other Postretirement Benefit Plans	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands)			
Service Cost	$ 1,340	$ 1,150	$ 172	$ 236
Interest Cost	3,663	4,021	976	1,202
Expected Return on Plan Assets	(4,991)	(4,837)	(2,030)	(2,119)
Amortization of Prior Service Cost (Credit)	26	28	(1,212)	(1,212)
Amortization of Net Actuarial Loss	1,893	2,233	311	373
Net Periodic Benefit Cost (Credit)	$ 1,931	$ 2,595	$ (1,783)	$ (1,520)

7. BUSINESS SEGMENTS

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

8. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

KPCo is exposed to certain market risks as a major power producer and participant in the wholesale electricity, natural gas, coal and emission allowance markets. 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

Risk Management Strategies

The strategy surrounding the use of derivative instruments primarily focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. The risk management strategies also include the use of derivative instruments for trading purposes, focusing on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which AEPSC transacts on behalf of KPCo. To accomplish these objectives, AEPSC, on behalf of KPCo, primarily employs risk management contracts including physical and financial forward purchase-and-sale contracts and, to a lesser extent, OTC swaps and options. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

AEPSC, on behalf of KPCo, enters into power, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline 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. 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 the KPCo's outstanding derivative contracts as of June 30, 2015 and December 31, 2014:

Notional Volume of Derivative Instruments

Primary Risk Exposure	Volume June 30, 2015	Volume December 31, 2014	Unit of Measure
	(in thousands)		
Commodity:			
Power	16,248	6,689	MWhs
Coal	93	233	Tons
Natural Gas	70	87	MMBtus
Heating Oil and Gasoline	357	261	Gallons
Interest Rate	$ 738	$ 1,047	USD

Cash Flow Hedging Strategies

AEPSC, on behalf of KPCo, enters into and designates as cash flow hedges certain derivative transactions for the purchase and sale of power ("Commodity") in order to manage the variable price risk related to forecasted purchases and sales. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and purchases. KPCo does not hedge all commodity price risk.

KPCo's vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of KPCo, enters into financial heating oil and gasoline derivative contracts in order to mitigate price risk of future fuel purchases. Cash flow hedge accounting for these derivative contracts was discontinued effective March 31, 2014. In March 2014, these contracts were grouped as "Commodity" with other risk management activities. KPCo does not hedge all fuel price risk.

AEPSC, on behalf of KPCo, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. AEPSC, on behalf of KPCo, also enters into interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. KPCo does not hedge all interest rate exposure.

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

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

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

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the June 30, 2015 and December 31, 2014 condensed balance sheets, KPCo netted $0 and $67 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $149 thousand and $24 thousand, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following tables represent the gross fair value impact of KPCo's derivative activity on the condensed balance sheets as of June 30, 2015 and December 31, 2014:

Fair Value of Derivative Instruments
June 30, 2015

	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate (a)**			
			(in thousands)			
Current Risk Management Assets	$ 10,056	$ —	$ —	$ 10,056	$ (2,988)	$ 7,068
Long-term Risk Management Assets	677	—	—	677	(58)	619
Total Assets	10,733	—	—	10,733	(3,046)	7,687
Current Risk Management Liabilities	5,784	—	—	5,784	(3,137)	2,647
Long-term Risk Management Liabilities	356	—	—	356	(58)	298
Total Liabilities	6,140	—	—	6,140	(3,195)	2,945
Total MTM Derivative Contract Net Assets (Liabilities)	$ 4,593	$ —	$ —	$ 4,593	$ 149	$ 4,742

Fair Value of Derivative Instruments
December 31, 2014

	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate (a)**			
			(in thousands)			
Current Risk Management Assets	$ 8,631	$ —	$ —	$ 8,631	$ (2,273)	$ 6,358
Long-term Risk Management Assets	1,060	—	—	1,060	(55)	1,005
Total Assets	9,691	—	—	9,691	(2,328)	7,363
Current Risk Management Liabilities	5,487	—	—	5,487	(2,231)	3,256
Long-term Risk Management Liabilities	477	—	—	477	(54)	423
Total Liabilities	5,964	—	—	5,964	(2,285)	3,679
Total MTM Derivative Contract Net Assets (Liabilities)	$ 3,727	$ —	$ —	$ 3,727	$ (43)	$ 3,684

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the condensed balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."

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

(c) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

The table below presents KPCo's activity of derivative risk management contracts for the three and six months ended June 30, 2015 and 2014:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three and Six Months Ended June 30, 2015 and 2014

	Three Months Ended June 30,		Six Months Ended June 30,	
Location of Gain (Loss)	**2015**	**2014**	**2015**	**2014**
		(in thousands)		
Electric Generation, Transmission and Distribution Revenues	$ 310	$ 904	$ 2,157	$ 7,844
Sales to AEP Affiliates	249	—	249	—
Other Operation Expense	(21)	—	(52)	—
Maintenance Expense	(29)	—	(71)	—
Purchased Electricity for Resale	319	—	2,573	—
Fuel and Other Consumables Used for Electric Generation	(4)	7	(13)	8
Regulatory Assets (a)	(301)	—	(267)	—
Regulatory Liabilities (a)	4,176	1,816	545	2,936
Total Gain on Risk Management Contracts	$ 4,699	$ 2,727	$ 5,121	$ 10,788

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

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

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

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on KPCo's condensed statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on KPCo's condensed statements of income depending on the relevant facts and circumstances. Certain derivatives that economically hedge future commodity risk are recorded in the same expense line item on the condensed statements of income as that of the associated risk. However, unrealized and some realized gains and losses for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains), in accordance with the accounting guidance for "Regulated Operations."

In connection with OPCo's June 2012 - May 2015 ESP, the PUCO ordered OPCo to conduct energy and capacity auctions for its entire SSO load for delivery beginning in June 2015, see Note 4 - Rate Matters. These auctions resulted in a range of products, including 12-month, 24-month, and 36-month periods. The delivery period for each contract is scheduled to start on the first day of June of each year, immediately following the auction. Certain affiliated Vertically Integrated Utility and Generation & Marketing segment entities participated in the auction process and were awarded tranches of OPCo's SSO load. The underlying contracts are derivatives subject to the accounting guidance for "Derivatives and Hedging" and are accounted for using MTM accounting, unless the contract has been designated as a normal purchase or normal sale. The following table represents the affiliated portion of KPCo's assets and liabilities on the condensed balance sheet resulting from these transactions:

June 30, 2015	
Risk Management Assets	Regulatory Liabilities and Deferred Investment Tax Credits
(in thousands)	
$ 924	$ 924

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).

Realized gains and losses on derivative contracts for the purchase and sale of power designated as cash flow hedges are included in Revenues or Purchased Electricity for Resale on KPCo's condensed statements of income, or in Regulatory Assets or Regulatory Liabilities on KPCo's condensed balance sheets, depending on the specific nature of the risk being hedged. During the three and six months ended June 30, 2015, KPCo did not designate power derivatives as cash flow hedges. During the three and six months ended June 30, 2014, KPCo designated power derivatives as cash flow hedges.

KPCo reclassifies gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on its condensed balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the condensed statements of income. Cash flow hedge accounting for these derivative contracts was immaterial and was discontinued effective March 31, 2014.

KPCo reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on its condensed balance sheets into Interest Expense on its condensed statements of income in those periods in which hedged interest payments occur. During the three and six months ended June 30, 2015 and 2014, KPCo did not designate any interest rate derivatives as cash flow hedges.

During the three and six months ended June 30, 2015 and 2014, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

For details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's condensed balance sheets and the reasons for changes in cash flow hedges for the three and six months ended June 30, 2015 and 2014, see Note 3.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's condensed balance sheets as of June 30, 2015 and December 31, 2014 were:

Impact of Cash Flow Hedges on the Condensed Balance Sheet
June 30, 2015

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ —	$ —	$ —
Hedging Liabilities (a)	—	—	—
AOCI Loss Net of Tax	—	(131)	(131)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	—	(60)	(60)

Impact of Cash Flow Hedges on the Condensed Balance Sheet
December 31, 2014

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ —	$ —	$ —
Hedging Liabilities (a)	—	—	—
AOCI Loss Net of Tax	—	(161)	(161)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	—	(60)	(60)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on KPCo's condensed balance sheets.

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of June 30, 2015, KPCo is not hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") its exposure to variability in future cash flows related to forecasted transactions.

Credit Risk

AEPSC, on behalf of KPCo, limits credit risk in KPCo's wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. AEPSC, on behalf of KPCo, uses Moody's, Standard and Poor's and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

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

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, KPCo is obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. KPCo has not experienced a downgrade below investment grade. The following table represents KPCo's exposure if credit ratings were to decline below a specified rating threshold as of June 30, 2015 and December 31, 2014:

	June 30, 2015	December 31, 2014
	(in thousands)	
Fair Value of Contracts with Credit Downgrade Triggers	$ —	$ —
Amount of Collateral KPCo Would Have been Required to Post for Derivative Contracts as well as Derivative and Non-Derivative Contracts Subject to the Same Master Netting Arrangement	—	—
Amount of Collateral KPCo Would Have Been Required to Post Attributable to RTOs and ISOs	660	1,303
Amount of Collateral Attributable to Other Contracts	65	14

In addition, a majority of KPCo's non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation in excess of $50 million. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted by KPCo and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering KPCo's contractual netting arrangements as of June 30, 2015 and December 31, 2014:

	June 30, 2015	December 31, 2014
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 1,397	$ 1,859
Amount of Cash Collateral Posted	—	—
Additional Settlement Liability if Cross Default Provision is Triggered	1,380	1,852

9. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability. The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with established risk management policies as approved by the Finance Committee of AEP's Board of Directors. The AEP System's market risk oversight staff independently monitors the risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (Regulated Risk Committee) various reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations and Chief Risk Officer.

For commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are nonbinding in nature, but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of the contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A significant portion of the Level 3 instruments have been economically hedged which greatly limits potential earnings volatility.

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of KPCo's Long-term Debt as of June 30, 2015 and December 31, 2014 are summarized in the following table:

	June 30, 2015		December 31, 2014	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 844,639	$ 945,825	$ 819,555	$ 948,967

Fair Value Measurements of Financial Assets and Liabilities

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 June 30, 2015 and December 31, 2014. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2015

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 36	$ 4,750	$ 5,913	$ (3,012)	$ 7,687
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 40	$ 5,927	$ 139	$ (3,161)	$ 2,945

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2014

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 42	$ 5,328	$ 4,320	$ (2,327)	$ 7,363
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 47	$ 5,523	$ 393	$ (2,284)	$ 3,679

(a) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(b) Substantially comprised of power contracts.

There were no transfers between Level 1 and Level 2 during the three and six months ended June 30, 2015 and 2014.

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

Three Months Ended June 30, 2015	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of March 31, 2015	$ 1,670
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(221)
Purchases, Issuances and Settlements (c)	(697)
Transfers out of Level 3 (e) (f)	240
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	4,782
Balance as of June 30, 2015	$ 5,774

Three Months Ended June 30, 2014	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of March 31, 2014	$ 1,450
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(754)
Purchases, Issuances and Settlements (c)	(13)
Transfers into Level 3 (d) (e)	37
Transfers out of Level 3 (e) (f)	1
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	2,865
Balance as of June 30, 2014	$ 3,586

Six Months Ended June 30, 2015	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of December 31, 2014	$ 3,927
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	365
Purchases, Issuances and Settlements (c)	(3,489)
Transfers out of Level 3 (e) (f)	240
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	4,731
Balance as of June 30, 2015	$ 5,774

Six Months Ended June 30, 2014	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of December 31, 2013	$ 2,171
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	5,375
Purchases, Issuances and Settlements (c)	(5,921)
Transfers into Level 3 (d) (e)	(749)
Transfers out of Level 3 (e) (f)	(1)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	2,711
Balance as of June 30, 2014	$ 3,586

(a) Included in revenues on KPCo’s condensed statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Represents the settlement of risk management commodity contracts for the reporting period.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(f) Represents existing assets or liabilities that were previously categorized as Level 3.
(g) 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.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions as of June 30, 2015 and December 31, 2014:

Significant Unobservable Inputs
June 30, 2015

	Fair Value		Valuation	Significant	Forward Price Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$ 2,774	$ 37	Discounted Cash Flow	Forward Market Price	$ 15.36	$ 56.30	$ 35.88
FTRs	3,139	102	Discounted Cash Flow	Forward Market Price	(6.16)	9.87	1.57
Total	$ 5,913	$ 139					

Significant Unobservable Inputs
December 31, 2014

	Fair Value		Valuation	Significant	Forward Price Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$ 2,088	$ 370	Discounted Cash Flow	Forward Market Price	$ 13.43	$ 123.02	$ 52.47
FTRs	2,232	23	Discounted Cash Flow	Forward Market Price	(14.63)	20.02	1.01
Total	$ 4,320	$ 393					

(a) Represents market prices in dollars per MWh.

The following table provides sensitivity of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts and FTRs as of June 30, 2015:

Sensitivity of Fair Value Measurements
June 30, 2015

Significant Unobservable Input	Position	Change in Input	Impact on Fair Value Measurement
Forward Market Price	Buy	Increase (Decrease)	Higher (Lower)
Forward Market Price	Sell	Increase (Decrease)	Lower (Higher)

10. INCOME TAXES

AEP System Tax Allocation Agreement

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

Federal and State Income Tax Audit Status

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2011. The IRS examination of years 2011, 2012 and 2013 started in April 2014. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to materially impact KPCo's net income.

KPCo and other AEP subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns. KPCo and other AEP subsidiaries are currently under examination in several state and local jurisdictions. However, it is possible that previously filed tax returns have positions that may be challenged by these tax authorities. Management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact KPCo's net income. KPCo is no longer subject to state or local income tax examinations by tax authorities for years before 2009.

11. FINANCING ACTIVITIES

Long-term Debt

Long-term debt issued during the first six months of 2015 is shown in the table below:

Type of Debt	Principal Amount (a) (in thousands)	Interest Rate (%)	Due Date
Other Long-term Debt	$ 25,000	Variable	2018

(a) Amount indicated on the statement of cash flows is net of issuance costs and premium or discount and will not tie to the issuance amount.

Dividend Restrictions

KPCo pays dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of KPCo to transfer funds to Parent in the form of dividends.

Federal Power Act

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

Leverage Restrictions

Pursuant to the credit agreement leverage restrictions, KPCo must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%.

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding loans to (borrowings from) the Utility Money Pool as of June 30, 2015 and December 31, 2014 are included in Advances to Affiliates and Advances from Affiliates, respectively, on KPCo's condensed balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the six months ended June 30, 2015 are described in the following table:

Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Borrowings from the Utility Money Pool as of June 30, 2015	Authorized Short-Term Borrowing Limit
		(in thousands)			
$ 52,477	$ 8,362	$ 21,382	$ 3,264	$ 27,176	$ 250,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool for the six months ended June 30, 2015 and 2014 are summarized in the following table:

Six Months Ended June 30,	Maximum Interest Rate for Funds Borrowed from the Utility Money Pool	Minimum Interest Rate for Funds Borrowed from the Utility Money Pool	Maximum Interest Rate for Funds Loaned to the Utility Money Pool	Minimum Interest Rate 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
2015	0.59%	0.39%	0.54%	0.42%	0.47%	0.51%
2014	0.33%	0.24%	0.33%	0.26%	0.28%	0.31%

Sale of Receivables – AEP Credit

Under a sale of receivables arrangement, KPCo sells, without recourse, certain of its customer accounts receivable and accrued unbilled revenue balances to AEP Credit and is charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for KPCo's receivables. The costs of customer accounts receivable sold are reported in Other Operation expense on KPCo's condensed statements of income. KPCo manages and services its accounts receivable sold.

AEP Credit's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables. The agreement was increased in June 2014 from $700 million and expires in June 2017.

KPCo's amounts of accounts receivable and accrued unbilled revenues sold under the sale of receivables agreement were $36.2 million and $46 million as of June 30, 2015 and December 31, 2014, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold for the three months ended June 30, 2015 and 2014 were $713 thousand and $633 thousand, respectively, and for the six months ended June 30, 2015 and 2014 were $1.6 million and $1.4 million, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit for the three months ended June 30, 2015 and 2014 were $118 million and $141 million, respectively, and for the six months ended June 30, 2015 and 2014 were $273 million and $320 million, respectively.

12. VARIABLE INTEREST ENTITIES

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether KPCo is the primary beneficiary of a VIE, management considers factors such as equity at risk, the amount of the VIE's variability KPCo absorbs, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE, variable interests held by related parties and other factors. Management believes that significant assumptions and judgments were applied consistently. KPCo is not the primary beneficiary of any VIE and has not provided financial or other support to any VIE that was not previously contractually required.

AEPSC provides certain managerial and professional services to AEP's subsidiaries. AEP is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. KPCo's total billings from AEPSC for the three months ended June 30, 2015 and 2014 were $16 million and $12 million, respectively, and for the six months ended June 30, 2015 and 2014 were $29 million and $25 million, respectively. The carrying amount of liabilities associated with AEPSC as of June 30, 2015 and December 31, 2014 was $5 million and $8 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant, Unit 1 and leases a 50% interest in Rockport Plant, Unit 2. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP has agreed to provide AEGCo with the funds necessary to satisfy all of the debt obligations of AEGCo. KPCo is considered to have a significant interest in AEGCo due to these transactions. KPCo is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. Due to AEP management's control over AEGCo, KPCo is not considered the primary beneficiary of AEGCo. In the event AEGCo would require financing or other support outside the billings to KPCo, this financing would be provided by AEP. Total billings from AEGCo for the three months ended June 30, 2015 and 2014 were $26 million and $28 million, respectively, and for the six months ended June 30, 2015 and 2014 were $49 million and $58 million, respectively. The carrying amount of liabilities associated with AEGCo as of June 30, 2015 and December 31, 2014 was $10 million and $9 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

13. PROPERTY, PLANT AND EQUIPMENT

Asset Retirement Obligations (ARO)

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

KPCo recorded an increase in asset retirement obligations in the second quarter of 2015, partially related to the final Coal Combustion Residual Rule, which was published in the Federal Register in April 2015. The Federal EPA now regulates the disposal and beneficial re-use of coal combustion residuals (CCR), including fly ash and bottom ash generated at coal-fired electric generating units and also FGD gypsum generated at some coal-fired plants. The Federal EPA regulates CCR as a non-hazardous solid waste and established minimum federal solid waste management standards. Noncash increases related to the CCR Rule are recorded as Property, Plant and Equipment.

The following is a reconciliation of the June 30, 2015 and December 31, 2014 aggregate carrying amounts of ARO for KPCo:

ARO as of December 31, 2014	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO as of June 30, 2015
		(in thousands)			
$ 65,699	$ 1,707	$ 2,145	$ (1,052)	$ 12,843	$ 81,342

14. DISPOSITION PLANT SEVERANCE

Management retired several generation plants or units of plants during 2015. These plant closures resulted in involuntary severances. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

The disposition plant severance activity for the six months ended June 30, 2015 is described in the following table:

Balance as of December 31, 2014	Expense Allocation from AEPSC	Incurred	Settled	Adjustments	Remaining Balance as of March 31, 2015
		(in thousands)			
$ 4,539	$ (2)	$ 69	$ (309) (a)	$ —	$ 4,297

(a) Settled includes amounts received from affiliates for expenses related to intercompany billing for operation and maintenance of affiliate plant.

KPCo recorded a charge of $4 million to Other Operation expense in December 2014 related to employees at the disposition plants. These expenses, net of adjustments, relate primarily to severance benefits and are included primarily in Other Operation expense on the condensed statements of income. The remaining liability is included in Other Current Liabilities on the condensed balance sheets. KPCo incurred additional charges during the second quarter of 2015 as severance plans were finalized after the plants were retired. Management does not expect additional severance costs to be incurred related to this initiative.

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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., an electric utility holding company.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AOCI	Accumulated Other Comprehensive Income.
ASU	Accounting Standards Update.
FASB	Financial Accounting Standards Board.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
PJM	Pennsylvania - New Jersey - Maryland regional transmission organization.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
REVENUES				
Electric Generation, Transmission and Distribution	$ 154,019	$ 198,477	$ 502,422	$ 631,212
Sales to AEP Affiliates	4,962	404	8,896	7,094
Other Revenues	212	201	600	469
TOTAL REVENUES	159,193	199,082	511,918	638,775
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	41,055	77,584	147,840	229,552
Purchased Electricity for Resale	4,167	773	22,128	5,943
Purchased Electricity from AEP Affiliates	28,835	28,526	78,103	87,886
Other Operation	21,587	19,555	61,667	58,360
Maintenance	17,788	16,082	54,973	52,448
Depreciation and Amortization	18,915	24,168	67,164	70,723
Taxes Other Than Income Taxes	5,933	5,129	16,932	15,719
TOTAL EXPENSES	138,280	171,817	448,807	520,631
OPERATING INCOME	20,913	27,265	63,111	118,144
Other Income (Expense):				
Interest Income	1	120	90	168
Carrying Costs Income	1,578	14	1,601	46
Allowance for Equity Funds Used During Construction	285	770	739	3,486
Interest Expense	(11,050)	(9,505)	(33,270)	(27,847)
INCOME BEFORE INCOME TAX EXPENSE	11,727	18,664	32,271	93,997
Income Tax Expense	4,731	6,863	11,969	34,390
NET INCOME	$ 6,996	$ 11,801	$ 20,302	$ 59,607

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

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Net Income	$ 6,996	$ 11,801	$ 20,302	$ 59,607
OTHER COMPREHENSIVE INCOME, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $8 and $8 for the Three Months Ended September 30, 2015 and 2014, Respectively, and $24 and $12 for the Nine Months Ended September 30, 2015 and 2014, Respectively	15	15	45	23
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $9 and $64 for the Three Months Ended September 30, 2015 and 2014, Respectively, and $27 and $189 for the Nine Months Ended September 30, 2015 and 2014, Respectively	17	118	50	351
TOTAL OTHER COMPREHENSIVE INCOME	32	133	95	374
TOTAL COMPREHENSIVE INCOME	$ 7,028	$ 11,934	$ 20,397	$ 59,981

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2013	$ 50,450	$ 614,648	$ 179,691	$ (5,420)	$ 839,369
Capital Contribution Returned to Parent		(100,000)			(100,000)
Common Stock Dividends			(100,000)		(100,000)
Other Changes in Common Shareholder's Equity		2,812			2,812
Net Income			59,607		59,607
Other Comprehensive Income				374	374
Pension and OPEB Adjustment Related to Kammer Plant				(1,308)	(1,308)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2014	$ 50,450	$ 517,460	$ 139,298	$ (6,354)	$ 700,854
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2014	$ 50,450	$ 517,460	$ 103,069	$ (7,336)	$ 663,643
Common Stock Dividends			(33,000)		(33,000)
Net Income			20,302		20,302
Other Comprehensive Income				95	95
Pension and OPEB Adjustment Related to Mitchell Plant				5,174	5,174
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2015	$ 50,450	$ 517,460	$ 90,371	$ (2,067)	$ 656,214

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
September 30, 2015 and December 31, 2014
(in thousands)
(Unaudited)

	September 30, 2015	December 31, 2014
CURRENT ASSETS		
Cash and Cash Equivalents	$ 541	$ 795
Accounts Receivable:		
Customers	13,536	21,125
Affiliated Companies	26,636	30,436
Accrued Unbilled Revenues	1,267	2,047
Miscellaneous	175	131
Allowance for Uncollectible Accounts	(287)	(87)
Total Accounts Receivable	41,327	53,652
Fuel	16,085	45,256
Materials and Supplies	27,689	34,499
Risk Management Assets – Nonaffiliated	3,894	6,358
Risk Management Assets – Affiliated	529	—
Deferred Income Tax Benefits	5,045	8,899
Accrued Tax Benefits	18,533	10,944
Prepayments and Other Current Assets	4,655	4,301
TOTAL CURRENT ASSETS	118,298	164,704
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,173,829	1,161,100
Transmission	561,732	558,099
Distribution	749,626	727,569
Other Property, Plant and Equipment (December 31, 2014 Amount Includes 2015 Plant Retirement)	67,182	521,327
Construction Work in Progress	55,208	39,194
Total Property, Plant and Equipment	2,607,577	3,007,289
Accumulated Depreciation and Amortization	884,630	1,026,208
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,722,947	1,981,081
OTHER NONCURRENT ASSETS		
Regulatory Assets	515,711	229,827
Long-term Risk Management Assets – Nonaffiliated	415	1,005
Employee Benefits and Pension Assets	14,126	12,810
Deferred Charges and Other Noncurrent Assets	9,298	20,081
TOTAL OTHER NONCURRENT ASSETS	539,550	263,723
TOTAL ASSETS	$ 2,380,795	$ 2,409,508

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2015 and December 31, 2014
(Unaudited)

	September 30, 2015	December 31, 2014
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 7,085	$ 45,128
Accounts Payable:		
General	43,836	42,315
Affiliated Companies	25,231	29,259
Long-term Debt Due Within One Year – Nonaffiliated	65,000	65,000
Risk Management Liabilities – Nonaffiliated	1,800	3,256
Customer Deposits	27,072	26,343
Accrued Taxes	15,094	18,873
Accrued Interest	6,159	7,824
Regulatory Liability for Over-Recovered Fuel Costs	694	1,770
Provision for Refund	8,939	31,033
Other Current Liabilities	38,283	38,986
TOTAL CURRENT LIABILITIES	239,193	309,787
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	779,680	754,555
Long-term Risk Management Liabilities – Nonaffiliated	200	423
Deferred Income Taxes	625,387	575,495
Regulatory Liabilities and Deferred Investment Tax Credits	2,535	22,522
Asset Retirement Obligations	60,776	63,479
Employee Benefits and Pension Obligations	11,091	12,531
Deferred Credits and Other Noncurrent Liabilities	5,719	7,073
TOTAL NONCURRENT LIABILITIES	1,485,388	1,436,078
TOTAL LIABILITIES	1,724,581	1,745,865
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER’S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	517,460	517,460
Retained Earnings	90,371	103,069
Accumulated Other Comprehensive Income (Loss)	(2,067)	(7,336)
TOTAL COMMON SHAREHOLDER’S EQUITY	656,214	663,643
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 2,380,795	$ 2,409,508

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2015 and 2014
(in thousands)
(Unaudited)

	Nine Months Ended September 30, 2015	2014
OPERATING ACTIVITIES		
Net Income	$ 20,302	$ 59,607
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	67,164	70,723
Deferred Income Taxes	44,673	(3,594)
Carrying Costs Income	(1,601)	(46)
Allowance for Equity Funds Used During Construction	(739)	(3,486)
Mark-to-Market of Risk Management Contracts	846	904
Pension Contributions to Qualified Plan Trust	(1,900)	(1,923)
Property Taxes	10,663	10,448
Fuel Over/Under-Recovery, Net	(1,076)	(11,841)
Provision for Refund	(22,094)	—
Change in Other Noncurrent Assets	(16,003)	(2,780)
Change in Other Noncurrent Liabilities	1,695	4,616
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	12,325	(14,008)
Fuel, Materials and Supplies	31,959	64,573
Accounts Payable	5,357	27,984
Accrued Taxes, Net	(11,368)	24,044
Accrued Interest	(1,664)	(1,114)
Other Current Assets	331	(621)
Other Current Liabilities	(8,445)	5,184
Net Cash Flows from Operating Activities	130,425	228,670
INVESTING ACTIVITIES		
Construction Expenditures	(84,943)	(73,505)
Change in Advances to Affiliates, Net	—	(9,577)
Other Investing Activities	1,496	(574)
Net Cash Flows Used for Investing Activities	(83,447)	(83,656)
FINANCING ACTIVITIES		
Capital Contribution Returned to Parent	—	(100,000)
Issuance of Long-term Debt – Nonaffiliated	24,546	183,970
Change in Advances from Affiliates, Net	(38,043)	(8,564)
Retirement of Long-term Debt – Nonaffiliated	—	(120,000)
Principal Payments for Capital Lease Obligations	(813)	(1,786)
Dividends Paid on Common Stock	(33,000)	(100,000)
Other Financing Activities	78	1,277
Net Cash Flows Used for Financing Activities	(47,232)	(145,103)
Net Decrease in Cash and Cash Equivalents	(254)	(89)
Cash and Cash Equivalents at Beginning of Period	795	743
Cash and Cash Equivalents at End of Period	$ 541	$ 654
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 34,168	$ 28,111
Net Cash Paid (Received) for Income Taxes	(24,547)	6,564
Noncash Acquisitions Under Capital Leases	171	1,273
Construction Expenditures Included in Current Liabilities as of September 30,	9,210	13,855

See Condensed Notes to Condensed Financial Statements beginning on page 8.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING MATTERS

General

The 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. Net income for the three and nine months ended September 30, 2015 is not necessarily indicative of results that may be expected for the year ending December 31, 2015. The condensed financial statements are unaudited and should be read in conjunction with the audited 2014 financial statements and notes thereto, which are included in KPCo's 2014 Annual Report.

Management reviewed subsequent events through October 22, 2015, the date that the third quarter 2015 report was issued.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management reviews the new accounting literature to determine its relevance, if any, to KPCo's business. The following final pronouncements will impact the financial statements.

ASU 2014-08 "Presentation of Financial Statements and Property, Plant and Equipment" (ASU 2014-08)

In April 2014, the FASB issued ASU 2014-08 changing the presentation of discontinued operations on the statements of income and other requirements for reporting discontinued operations. Under the new standard, a disposal of a component or a group of components of an entity is required to be reported in discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity's operations and financial results when the component meets the criteria to be classified as held-for-sale or is disposed. The amendments in this update also require additional disclosures about discontinued operations and disposal of an individually significant component of an entity that does not qualify for discontinued operations. This standard must be prospectively applied to all reporting periods presented in financial reports issued after the effective date.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2014. If applicable, this standard will change the presentation of financial statements but will not affect the calculation of net income, comprehensive income or earnings per share. Management adopted ASU 2014-08 effective January 1, 2015. There were no events requiring the application of this new accounting guidance.

ASU 2014-09 "Revenue from Contracts with Customers" (ASU 2014-09)

In May 2014, the FASB issued ASU 2014-09 clarifying the method used to determine the timing and requirements for revenue recognition on the statements of income. Under the new standard, an entity must identify the performance obligations in a contract, determine the transaction price and allocate the price to specific performance obligations to recognize the revenue when the obligation is completed. The amendments in this update also require disclosure of sufficient information to allow users to understand the nature, amount, timing and uncertainty of revenue and cash flow arising from contracts.

The FASB deferred implementation of ASU 2014-09 under the terms in ASU 2015-14, "Revenue from Contracts with Customers (Topic: 606): Deferral of the Effective Date." The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017. Early adoption is permitted for annual periods beginning after December 15, 2016. As applicable, this standard may change the amount of revenue recognized in the income statements in each reporting period. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on revenue or net income. Management plans to adopt ASU 2014-09 effective January 1, 2018.

ASU 2015-01 "Income Statement – Extraordinary and Unusual Items" (ASU 2015-01)

In January 2015, the FASB issued ASU 2015-01 eliminating the concept of extraordinary items for presentation on the face of the income statement. Under the new standard, a material event or transaction that is unusual in nature, infrequent or both shall be reported as a separate component of income from continuing operations. Alternatively, it may be disclosed in the notes to financial statements.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015. Early adoption is permitted if applied from the beginning of a fiscal year. As applicable, this standard may change the presentation of amounts in the income statements. Management plans to adopt ASU 2015-01 effective January 1, 2016.

ASU 2015-03 "Simplifying the Presentation of Debt Issuance Costs" (ASU 2015-03)

In April 2015, the FASB issued ASU 2015-03 simplifying the presentation of debt issuance costs on the balance sheets. Under the new standard, debt issuance costs related to a recognized debt liability will be presented on the balance sheets as a direct deduction from the carrying amount of that debt liability, consistent with discounts. KPCo includes debt issuance costs in Deferred Charges and Other Noncurrent Assets on the condensed balance sheets. Debt issuance costs represent less than 1% of total long-term debt.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015 with early adoption permitted. Management intends to early adopt ASU 2015-03 for the 2015 Annual Report.

ASU 2015-05 "Customer's Accounting for Fees Paid in a Cloud Computing Arrangement" (ASU 2015-05)

In April 2015, the FASB issued ASU 2015-05 providing guidance to customers about whether a cloud computing arrangement includes a software license. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2015 with early adoption permitted. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. Management plans to adopt ASU 2015-05 effective January 1, 2016.

ASU 2015-11 "Simplifying the Measurement of Inventory" (ASU 2015-11)

In July 2015, the FASB issued ASU 2015-11 simplifying the guidance on the subsequent measurement of inventory, excluding inventory measured using last-in, first-out or the retail inventory method. Under the new standard, inventory should be at the lower of cost and net realizable value. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016 with early adoption permitted. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. Management plans to adopt ASU 2015-11 effective January 1, 2017.

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI for the three and nine months ended September 30, 2015 and 2014. All amounts in the following tables are presented net of related income taxes.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2015

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
		(in thousands)		
Balance in AOCI as of June 30, 2015	$ —	$ (131)	$ (1,968)	$ (2,099)
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	—	15	17	32
Net Current Period Other Comprehensive Income	—	15	17	32
Balance in AOCI as of September 30, 2015	$ —	$ (116)	$ (1,951)	$ (2,067)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2014

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
		(in thousands)		
Balance in AOCI as of June 30, 2014	$ —	$ (191)	$ (6,296)	$ (6,487)
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	—	15	118	133
Net Current Period Other Comprehensive Income	—	15	118	133
Balance in AOCI as of September 30, 2014	$ —	$ (176)	$ (6,178)	$ (6,354)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2015

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
		(in thousands)		
Balance in AOCI as of December 31, 2014	$ —	$ (161)	$ (7,175)	$ (7,336)
Change in Fair Value Recognized in AOCI	—	—	—	—
Amounts Reclassified from AOCI	—	45	50	95
Net Current Period Other Comprehensive Income	—	45	50	95
Pension and OPEB Adjustment Related to Mitchell Plant	—	—	5,174	5,174
Balance in AOCI as of September 30, 2015	$ —	$ (116)	$ (1,951)	$ (2,067)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2014

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
		(in thousands)		
Balance in AOCI as of December 31, 2013	$ 23	$ (222)	$ (5,221)	$ (5,420)
Change in Fair Value Recognized in AOCI	348	—	—	348
Amounts Reclassified from AOCI	(371)	46	351	26
Net Current Period Other Comprehensive Income (Loss)	(23)	46	351	374
Pension and OPEB Adjustment Related to Kammer Plant	—	—	(1,308)	(1,308)
Balance in AOCI as of September 30, 2014	$ —	$ (176)	$ (6,178)	$ (6,354)

Reclassifications from Accumulated Other Comprehensive Income

The following tables provide details of reclassifications from AOCI for the three and nine months ended September 30, 2015 and 2014. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 6 for additional details.

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended September 30, 2015 and 2014

	Amount of (Gain) Loss Reclassified from AOCI	
	Three Months Ended September 30,	
	2015	2014
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Purchased Electricity for Resale	$ —	$ —
Subtotal – Commodity	—	—
Interest Rate and Foreign Currency:		
Interest Expense	23	23
Subtotal – Interest Rate and Foreign Currency	23	23
Reclassifications from AOCI, before Income Tax (Expense) Credit	23	23
Income Tax (Expense) Credit	8	8
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	15	15
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(10)	(55)
Amortization of Actuarial (Gains)/Losses	35	236
Reclassifications from AOCI, before Income Tax (Expense) Credit	25	181
Income Tax (Expense) Credit	8	63
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	17	118
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ 32	$ 133

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Nine Months Ended September 30, 2015 and 2014

	Amount of (Gain) Loss Reclassified from AOCI	
	Nine Months Ended September 30,	
	2015	2014
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Purchased Electricity for Resale	$ —	$ (512)
Other Operation Expense	—	(3)
Maintenance Expense	—	(5)
Property, Plant and Equipment	—	(6)
Regulatory Assets/(Liabilities), Net (a)	—	(43)
Subtotal – Commodity	—	(569)
Interest Rate and Foreign Currency:		
Interest Expense	69	69
Subtotal – Interest Rate and Foreign Currency	69	69
Reclassifications from AOCI, before Income Tax (Expense) Credit	69	(500)
Income Tax (Expense) Credit	24	(175)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	45	(325)
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(30)	(162)
Amortization of Actuarial (Gains)/Losses	106	702
Reclassifications from AOCI, before Income Tax (Expense) Credit	76	540
Income Tax (Expense) Credit	26	189
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	50	351
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ 95	$ 26

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

4. RATE MATTERS

As discussed in KPCo's 2014 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo's 2014 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 2015 and updates KPCo's 2014 Annual Report.

Regulatory Assets Pending Final Regulatory Approval

Noncurrent Regulatory Assets	September 30, 2015	December 31, 2014
	(in thousands)	
Regulatory Assets Currently Not Earning a Return		
Storm Related Costs	$ 4,377	$ 12,146
Asset Retirement Obligation	—	8,287
Total Regulatory Assets Pending Final Regulatory Approval	$ 4,377	$ 20,433

If these costs are ultimately determined not to be recoverable, it could reduce future net income and cash flows and impact financial condition.

Plant Transfer

In October 2013, the KPSC issued an order that approved a modified settlement agreement which included the approval to transfer to KPCo a one-half interest in the Mitchell Plant, comprising 780 MW of average annual generating capacity. In December 2013, the transfer of a one-half interest in the Mitchell Plant to KPCo was completed. In December 2013, the Attorney General filed an appeal of the order with the Franklin County Circuit Court. In April 2015, the Franklin County Circuit Court issued an order that affirmed the KPSC's October 2013 order. In May 2015, the Attorney General filed an appeal with the Franklin County Circuit Court of the April 2015 order that had affirmed the KPSC's order.

Consistent with KPCo's December 2012 plant transfer filing that was approved by the KPSC, Big Sandy Plant, Unit 2 was retired in May 2015. Upon retirement, $194 million was reclassified as Regulatory Assets on the condensed balance sheet related to the net book value of Big Sandy Plant, Unit 2 and the related asset retirement obligations, costs of removal and materials and supplies. These regulatory assets will be amortized over 25 years, effective July 2015.

If any part of the KPSC order is overturned, it could reduce future net income and cash flows and impact financial condition.

Kentucky Fuel Adjustment Clause Review

In January 2015, the KPSC issued an order disallowing certain FAC costs during the period of January 2014 through May 2015 while KPCo owned and operated both Big Sandy Plant, Unit 2 and its one-half interest in the Mitchell Plant. As a result of this order, KPCo recorded a regulatory disallowance of $36 million in December 2014. In February 2015, KPCo filed an appeal of this order with the Franklin County Circuit Court. In September 2015, the Franklin County Circuit Court issued an order that dismissed all appeals filed related to this FAC review, as agreed to by the parties to the stipulation agreement in the "2014 Kentucky Base Rate Case" discussed below.

2014 Kentucky Base Rate Case

In December 2014, KPCo filed a request with the KPSC for a net increase in rates of $70 million. In April 2015, a non-unanimous stipulation agreement between KPCo and certain intervenors was filed with the KPSC. The parties to the stipulation recommended a net revenue increase of $45 million, which consisted of a $68 million increase in rider rates, offset by a $23 million decrease in annual base rates, to be effective July 2015. The proposed net increase reflects KPCo's ownership interest in the Mitchell Plant, riders to recover the Big Sandy Plant retirement and operational costs and the inclusion of an environmental compliance plan. Additionally, the agreement included (a) recovery of $12 million of deferred storm costs, (b) any difference between the actual off-system sales margins and the $15 million included in the proposed annual base rates to be shared with 75% to the customer and 25% to KPCo and (c) dismissal of the KPCo and the Kentucky Industrial Utility Customers appeals of the KPSC order in the KPCo fuel adjustment clause review. See "Kentucky Fuel Adjustment Clause Review" discussed above.

In June 2015, the KPSC issued an order that approved a modified stipulation agreement. The order approved a net revenue increase of $45 million, as proposed in the stipulation agreement, and contained modifications that included (a) approval to recover $2 million of IGCC and certain carbon capture study costs, both over 25 years, (b) no deferral of certain PJM costs and (c) denial of the recovery of certain potential purchased power costs through a rider.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, KPCo's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. Contingent liabilities are accrued only when management concludes that it is both probable that a liability has been incurred at the date of the financial statements and the amount of loss can be reasonably estimated. When determined that it is not probable, but rather reasonably possible that a liability has been incurred at the date of the financial statements, such contingencies and the possible loss or range of loss are disclosed if such estimate can be made. Any estimated range is based on currently available information and involves elements of judgment and significant uncertainties. Any estimated range of possible loss may not represent the maximum possible loss exposure. Circumstances change over time and actual results may vary significantly from estimates.

For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements. The Commitments, Guarantees and Contingencies note within KPCo's 2014 Annual Report should be read in conjunction with this report.

GUARANTEES

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

Letter of Credit

KPCo has $65 million of variable rate Pollution Control Bonds supported by a bilateral letter of credit for $66 million. The letter of credit matures in June 2017.

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of September 30, 2015, there were no material liabilities recorded for any indemnifications.

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

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, KPCo is committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance. As of September 30, 2015, the maximum potential loss for these lease agreements was $1.6 million assuming the fair value of the equipment is zero at the end of the lease term.

6. BENEFIT PLANS

KPCo participates in an AEP sponsored qualified pension plan and an unfunded nonqualified pension plan. Substantially all of KPCo's employees are covered by the qualified plan or both the qualified and nonqualified pension plans. KPCo also participates in OPEB plans sponsored by AEP to provide health and life insurance benefits for retired employees.

Components of Net Periodic Benefit Cost

The following tables provide the components of KPCo's net periodic benefit cost (credit) for the plans for the three and nine months ended September 30, 2015 and 2014:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)			
Service Cost	$ 670	$ 574	$ 86	$ 118
Interest Cost	1,832	2,010	488	602
Expected Return on Plan Assets	(2,495)	(2,418)	(1,015)	(1,061)
Amortization of Prior Service Cost (Credit)	13	15	(606)	(606)
Amortization of Net Actuarial Loss	945	1,117	155	187
Net Periodic Benefit Cost (Credit)	$ 965	$ 1,298	$ (892)	$ (760)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)			
Service Cost	$ 2,010	$ 1,724	$ 258	$ 354
Interest Cost	5,495	6,031	1,464	1,804
Expected Return on Plan Assets	(7,486)	(7,255)	(3,045)	(3,180)
Amortization of Prior Service Cost (Credit)	39	43	(1,818)	(1,818)
Amortization of Net Actuarial Loss	2,838	3,350	466	560
Net Periodic Benefit Cost (Credit)	$ 2,896	$ 3,893	$ (2,675)	$ (2,280)

7. BUSINESS SEGMENTS

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

8. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

KPCo is exposed to certain market risks as a major power producer and participant in the wholesale electricity, natural gas, coal and emission allowance markets. 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

Risk Management Strategies

The strategy surrounding the use of derivative instruments primarily focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. The risk management strategies also include the use of derivative instruments for trading purposes, focusing on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which AEPSC transacts on behalf of KPCo. To accomplish these objectives, AEPSC, on behalf of KPCo, primarily employs risk management contracts including physical and financial forward purchase-and-sale contracts and, to a lesser extent, OTC swaps and options. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

AEPSC, on behalf of KPCo, enters into power, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline 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. 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 September 30, 2015 and December 31, 2014:

Notional Volume of Derivative Instruments

	Volume		
Primary Risk Exposure	**September 30, 2015**	**December 31, 2014**	**Unit of Measure**
	(in thousands)		
Commodity:			
Power	12,490	6,689	MWhs
Coal	47	233	Tons
Natural Gas	53	87	MMBtus
Heating Oil and Gasoline	428	261	Gallons
Interest Rate	$ 544	$ 1,047	USD

Cash Flow Hedging Strategies

AEPSC, on behalf of KPCo, enters into and designates as cash flow hedges certain derivative transactions for the purchase and sale of power ("Commodity") in order to manage the variable price risk related to forecasted purchases and sales. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and purchases. KPCo does not hedge all commodity price risk.

KPCo's vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of KPCo, enters into financial heating oil and gasoline derivative contracts in order to mitigate price risk of future fuel purchases. Cash flow hedge accounting for these derivative contracts was discontinued effective March 31, 2014. In March 2014, these contracts were grouped as "Commodity" with other risk management activities. KPCo does not hedge all fuel price risk.

AEPSC, on behalf of KPCo, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. AEPSC, on behalf of KPCo, also enters into interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. KPCo does not hedge all interest rate exposure.

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

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

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

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the September 30, 2015 and December 31, 2014 condensed balance sheets, KPCo netted $0 and $67 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $159 thousand and $24 thousand, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following tables represent the gross fair value impact of KPCo's derivative activity on the condensed balance sheets as of September 30, 2015 and December 31, 2014:

Fair Value of Derivative Instruments
September 30, 2015

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in thousands)					
Current Risk Management Assets - Nonaffiliated and Affiliated	$ 6,149	$ —	$ —	$ 6,149	$ (1,726)	$ 4,423
Long-term Risk Management Assets - Nonaffiliated	505	—	—	505	(90)	415
Total Assets	6,654	—	—	6,654	(1,816)	4,838
Current Risk Management Liabilities - Nonaffiliated	3,649	—	—	3,649	(1,849)	1,800
Long-term Risk Management Liabilities - Nonaffiliated	326	—	—	326	(126)	200
Total Liabilities	3,975	—	—	3,975	(1,975)	2,000
Total MTM Derivative Contract Net Assets (Liabilities)	$ 2,679	$ —	$ —	$ 2,679	$ 159	$ 2,838

Fair Value of Derivative Instruments
December 31, 2014

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in thousands)					
Current Risk Management Assets - Nonaffiliated	$ 8,631	$ —	$ —	$ 8,631	$ (2,273)	$ 6,358
Long-term Risk Management Assets - Nonaffiliated	1,060	—	—	1,060	(55)	1,005
Total Assets	9,691	—	—	9,691	(2,328)	7,363
Current Risk Management Liabilities - Nonaffiliated	5,487	—	—	5,487	(2,231)	3,256
Long-term Risk Management Liabilities - Nonaffiliated	477	—	—	477	(54)	423
Total Liabilities	5,964	—	—	5,964	(2,285)	3,679
Total MTM Derivative Contract Net Assets (Liabilities)	$ 3,727	$ —	$ —	$ 3,727	$ (43)	$ 3,684

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the condensed balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."
(c) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

The table below presents KPCo's activity of derivative risk management contracts for the three and nine months ended September 30, 2015 and 2014:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three and Nine Months Ended September 30, 2015 and 2014

	Three Months Ended September 30,		Nine Months Ended September 30,	
Location of Gain (Loss)	**2015**	**2014**	**2015**	**2014**
		(in thousands)		
Electric Generation, Transmission and Distribution Revenues	$ 77	$ 2,963	$ 2,234	$ 10,807
Sales to AEP Affiliates	728	—	977	—
Other Operation Expense	(23)	—	(75)	—
Maintenance Expense	(40)	—	(111)	—
Purchased Electricity for Resale	758	—	3,331	—
Fuel and Other Consumables Used for Electric Generation	(7)	(3)	(20)	5
Regulatory Assets (a)	624	(1,493)	944	(1,236)
Regulatory Liabilities (a)	(919)	(1,314)	(962)	1,365
Total Gain on Risk Management Contracts	$ 1,198	$ 153	$ 6,318	$ 10,941

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

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

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

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on KPCo's condensed statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on KPCo's condensed statements of income depending on the relevant facts and circumstances. Certain derivatives that economically hedge future commodity risk are recorded in the same expense line item on the condensed statements of income as that of the associated risk. However, unrealized and some realized gains and losses for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains), in accordance with the accounting guidance for "Regulated Operations."

In connection with OPCo's June 2012 - May 2015 ESP, the PUCO ordered OPCo to conduct energy and capacity auctions for its entire SSO load for delivery beginning in June 2015, see Note 4 - Rate Matters. These auctions resulted in a range of products, including 12-month, 24-month, and 36-month periods. The delivery period for each contract is scheduled to start on the first day of June of each year, immediately following the auction. Certain affiliated Vertically Integrated Utility and Generation & Marketing segment entities participated in the auction process and were awarded tranches of OPCo's SSO load. The underlying contracts are derivatives subject to the accounting guidance for "Derivatives and Hedging" and are accounted for using MTM accounting, unless the contract has been designated as a normal purchase or normal sale.

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).

Realized gains and losses on derivative contracts for the purchase and sale of power designated as cash flow hedges are included in Revenues or Purchased Electricity for Resale on KPCo's condensed statements of income, or in Regulatory Assets or Regulatory Liabilities on KPCo's condensed balance sheets, depending on the specific nature of the risk being hedged. During the three and nine months ended September 30, 2015, KPCo did not designate power derivatives as cash flow hedges. During the three and nine months ended September 30, 2014, KPCo designated power derivatives as cash flow hedges.

KPCo reclassifies gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on its condensed balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the condensed statements of income. Cash flow hedge accounting for these derivative contracts was immaterial and was discontinued effective March 31, 2014.

KPCo reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on its condensed balance sheets into Interest Expense on its condensed statements of income in those periods in which hedged interest payments occur. During the three and nine months ended September 30, 2015 and 2014, KPCo did not designate any interest rate derivatives as cash flow hedges.

During the three and nine months ended September 30, 2015 and 2014, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

For details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's condensed balance sheets and the reasons for changes in cash flow hedges for the three and nine months ended September 30, 2015 and 2014, see Note 3.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's condensed balance sheets as of September 30, 2015 and December 31, 2014 were:

Impact of Cash Flow Hedges on the Condensed Balance Sheet
September 30, 2015

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ —	$ —	$ —
Hedging Liabilities (a)	—	—	—
AOCI Loss Net of Tax	—	(116)	(116)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	—	(60)	(60)

Impact of Cash Flow Hedges on the Condensed Balance Sheet
December 31, 2014

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ —	$ —	$ —
Hedging Liabilities (a)	—	—	—
AOCI Loss Net of Tax	—	(161)	(161)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	—	(60)	(60)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on KPCo's condensed balance sheets.

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of September 30, 2015, KPCo is not hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") its exposure to variability in future cash flows related to forecasted transactions.

Credit Risk

AEPSC, on behalf of KPCo, limits credit risk in KPCo's wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. AEPSC, on behalf of KPCo, uses Moody's, Standard and Poor's and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

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

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, KPCo is obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. KPCo has not experienced a downgrade below investment grade. The following table represents KPCo's exposure if credit ratings were to decline below a specified rating threshold as of September 30, 2015 and December 31, 2014:

	September 30, 2015	December 31, 2014
	(in thousands)	
Fair Value of Contracts with Credit Downgrade Triggers	$ —	$ —
Amount of Collateral KPCo Would Have been Required to Post for Derivative Contracts as well as Derivative and Non-Derivative Contracts Subject to the Same Master Netting Arrangement	—	—
Amount of Collateral KPCo Would Have Been Required to Post Attributable to RTOs and ISOs	599	1,303
Amount of Collateral Attributable to Other Contracts	20	14

In addition, a majority of KPCo's non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation in excess of $50 million. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted by KPCo and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering KPCo's contractual netting arrangements as of September 30, 2015 and December 31, 2014:

	September 30, 2015	December 31, 2014
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 1,091	$ 1,859
Amount of Cash Collateral Posted	—	—
Additional Settlement Liability if Cross Default Provision is Triggered	1,087	1,852

9. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability. The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with established risk management policies as approved by the Finance Committee of AEP's Board of Directors. The AEP System's market risk oversight staff independently monitors the risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (Regulated Risk Committee) various reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations and Chief Risk Officer.

For commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are nonbinding in nature, but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of the contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A significant portion of the Level 3 instruments have been economically hedged which greatly limits potential earnings volatility.

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of KPCo's Long-term Debt as of September 30, 2015 and December 31, 2014 are summarized in the following table:

	September 30, 2015		December 31, 2014	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 844,680	$ 949,157	$ 819,555	$ 948,967

Fair Value Measurements of Financial Assets and Liabilities

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 September 30, 2015 and December 31, 2014. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2015

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets – Nonaffiliated and Affiliated					
Risk Management Commodity Contracts (a) (b)	$ 38	$ 3,025	$ 3,582	$ (1,807)	$ 4,838
Liabilities:					
Risk Management Liabilities – Nonaffiliated					
Risk Management Commodity Contracts (a) (b)	$ 41	$ 3,790	$ 135	$ (1,966)	$ 2,000

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2014

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets – Nonaffiliated					
Risk Management Commodity Contracts (a) (b)	$ 42	$ 5,328	$ 4,320	$ (2,327)	$ 7,363
Liabilities:					
Risk Management Liabilities – Nonaffiliated					
Risk Management Commodity Contracts (a) (b)	$ 47	$ 5,523	$ 393	$ (2,284)	$ 3,679

(a) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(b) Substantially comprised of power contracts.

There were no transfers between Level 1 and Level 2 during the three and nine months ended September 30, 2015 and 2014.

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

Three Months Ended September 30, 2015	Net Risk Management Assets (Liabilities) (a)
	(in thousands)
Balance as of June 30, 2015	$ 5,774
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	34
Purchases, Issuances and Settlements (d)	(2,031)
Changes in Fair Value Allocated to Regulated Jurisdictions (h)	(330)
Balance as of September 30, 2015	$ 3,447

Three Months Ended September 30, 2014	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of June 30, 2014	$ 3,586
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	(1,118)
Purchases, Issuances and Settlements (d)	(270)
Transfers into Level 3 (e) (f)	(1)
Transfers out of Level 3 (f) (g)	(6)
Changes in Fair Value Allocated to Regulated Jurisdictions (h)	980
Balance as of September 30, 2014	$ 3,171

Nine Months Ended September 30, 2015	Net Risk Management Assets (Liabilities) (a)
	(in thousands)
Balance as of December 31, 2014	$ 3,927
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	698
Purchases, Issuances and Settlements (d)	(4,076)
Transfers out of Level 3 (f) (g)	240
Changes in Fair Value Allocated to Regulated Jurisdictions (h)	2,658
Balance as of September 30, 2015	$ 3,447

Nine Months Ended September 30, 2014	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of December 31, 2013	$ 2,171
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	5,444
Purchases, Issuances and Settlements (d)	(6,008)
Transfers into Level 3 (e) (f)	(750)
Transfers out of Level 3 (f) (g)	(7)
Changes in Fair Value Allocated to Regulated Jurisdictions (h)	2,321
Balance as of September 30, 2014	$ 3,171

(a) Includes both affiliated and nonaffiliated transactions.
(b) Included in revenues on KPCo's condensed statements of income.
(c) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(d) Represents the settlement of risk management commodity contracts for the reporting period.
(e) Represents existing assets or liabilities that were previously categorized as Level 2.
(f) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(g) Represents existing assets or liabilities that were previously categorized as Level 3.
(h) 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.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions as of September 30, 2015 and December 31, 2014:

Significant Unobservable Inputs
September 30, 2015

	Fair Value		Valuation	Significant Unobservable	Forward Price Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$ 2,099	$ 92	Discounted Cash Flow	Forward Market Price	$ 13.03	$ 48.17	$ 34.76
FTRs	1,483	43	Discounted Cash Flow	Forward Market Price	(5.95)	11.60	1.53
Total	$ 3,582	$ 135					

Significant Unobservable Inputs
December 31, 2014

	Fair Value		Valuation	Significant Unobservable	Forward Price Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$ 2,088	$ 370	Discounted Cash Flow	Forward Market Price	$ 13.43	$ 123.02	$ 52.47
FTRs	2,232	23	Discounted Cash Flow	Forward Market Price	(14.63)	20.02	1.01
Total	$ 4,320	$ 393					

(a) Represents market prices in dollars per MWh.

The following table provides sensitivity of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts and FTRs as of September 30, 2015:

Sensitivity of Fair Value Measurements
September 30, 2015

Significant Unobservable Input	Position	Change in Input	Impact on Fair Value Measurement
Forward Market Price	Buy	Increase (Decrease)	Higher (Lower)
Forward Market Price	Sell	Increase (Decrease)	Lower (Higher)

10. INCOME TAXES

AEP System Tax Allocation Agreement

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

Federal and State Income Tax Audit Status

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2011. The IRS examination of years 2011, 2012 and 2013 started in April 2014. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to materially impact KPCo's net income.

KPCo and other AEP subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns. KPCo and other AEP subsidiaries are currently under examination in several state and local jurisdictions. However, it is possible that previously filed tax returns have positions that may be challenged by these tax authorities. Management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact KPCo's net income. KPCo is no longer subject to state or local income tax examinations by tax authorities for years before 2009.

11. FINANCING ACTIVITIES

Long-term Debt

Long-term debt issued during the first nine months of 2015 is shown in the table below:

Type of Debt	Principal Amount (a)	Interest Rate	Due Date
	(in thousands)	(%)	
Other Long-term Debt	$ 25,000	Variable	2018

(a) Amount indicated on the statement of cash flows is net of issuance costs and premium or discount and will not tie to the issuance amount.

In October 2015, KPCo drew the remaining $25 million on an existing $75 million variable rate credit facility due in 2018.

Dividend Restrictions

KPCo pays dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of KPCo to transfer funds to Parent in the form of dividends.

Federal Power Act

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

Leverage Restrictions

Pursuant to the credit agreement leverage restrictions, KPCo must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%.

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding borrowings from the Utility Money Pool as of September 30, 2015 and December 31, 2014 are included in Advances from Affiliates on KPCo's condensed balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the nine months ended September 30, 2015 are described in the following table:

Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Borrowings from the Utility Money Pool as of September 30, 2015	Authorized Short-Term Borrowing Limit
		(in thousands)			
$ 52,477	$ 8,362	$ 20,573	$ 3,156	$ 7,085	$ 250,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool for the nine months ended September 30, 2015 and 2014 are summarized in the following table:

Nine Months Ended September 30,	Maximum Interest Rate for Funds Borrowed from the Utility Money Pool	Minimum Interest Rate for Funds Borrowed from the Utility Money Pool	Maximum Interest Rate for Funds Loaned to the Utility Money Pool	Minimum Interest Rate 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
2015	0.59%	0.39%	0.54%	0.42%	0.46%	0.51%
2014	0.33%	0.24%	0.33%	0.26%	0.28%	0.28%

Sale of Receivables – AEP Credit

Under a sale of receivables arrangement, KPCo sells, without recourse, certain of its customer accounts receivable and accrued unbilled revenue balances to AEP Credit and is charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for KPCo's receivables. The costs of customer accounts receivable sold are reported in Other Operation expense on KPCo's condensed statements of income. KPCo manages and services its accounts receivable sold.

AEP Credit's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables. The agreement was increased in June 2014 from $700 million and expires in June 2017.

KPCo's amounts of accounts receivable and accrued unbilled revenues sold under the sale of receivables agreement were $33.6 million and $46 million as of September 30, 2015 and December 31, 2014, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold for the three months ended September 30, 2015 and 2014 were $814 thousand and $672 thousand, respectively, and for the nine months ended September 30, 2015 and 2014 were $2.4 million and $2.1 million, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit for the three months ended September 30, 2015 and 2014 were $127 million and $142 million, respectively, and for the nine months ended September 30, 2015 and 2014 were $400 million and $462 million, respectively.

12. VARIABLE INTEREST ENTITIES

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether KPCo is the primary beneficiary of a VIE, management considers factors such as equity at risk, the amount of the VIE's variability KPCo absorbs, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE, variable interests held by related parties and other factors. Management believes that significant assumptions and judgments were applied consistently. KPCo is not the primary beneficiary of any VIE and has not provided financial or other support to any VIE that was not previously contractually required.

AEPSC provides certain managerial and professional services to AEP's subsidiaries. AEP is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. KPCo's total billings from AEPSC for the three months ended September 30, 2015 and 2014 were $15 million and $12.1 million, respectively, and for the nine months ended September 30, 2015 and 2014 were $43.8 million and $36.7 million, respectively. The carrying amount of liabilities associated with AEPSC as of September 30, 2015 and December 31, 2014 was $5.6 million and $8.2 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant, Unit 1 and leases a 50% interest in Rockport Plant, Unit 2. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP has agreed to provide AEGCo with the funds necessary to satisfy all of the debt obligations of AEGCo. KPCo is considered to have a significant interest in AEGCo due to these transactions. KPCo is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. Due to AEP management's control over AEGCo, KPCo is not considered the primary beneficiary of AEGCo. In the event AEGCo would require financing or other support outside the billings to KPCo, this financing would be provided by AEP. Total billings from AEGCo for the three months ended September 30, 2015 and 2014 were $28.8 million and $28.5 million, respectively, and for the nine months ended September 30, 2015 and 2014 were $78.1 million and $86.6 million, respectively. The carrying amount of liabilities associated with AEGCo as of September 30, 2015 and December 31, 2014 was $7.7 million and $9 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

13. PROPERTY, PLANT AND EQUIPMENT

Asset Retirement Obligations (ARO)

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

KPCo recorded an increase in asset retirement obligations in the second quarter of 2015, partially related to the final Coal Combustion Residual Rule, which was published in the Federal Register in April 2015. The Federal EPA now regulates the disposal and beneficial re-use of coal combustion residuals (CCR), including fly ash and bottom ash generated at coal-fired electric generating units and also FGD gypsum generated at some coal-fired plants. The Federal EPA regulates CCR as a non-hazardous solid waste and established minimum federal solid waste management standards. Noncash increases related to the CCR Rule are recorded as Property, Plant and Equipment.

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

ARO as of December 31, 2014	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates (a)	ARO as of September 30, 2015
		(in thousands)			
$ 65,699	$ 2,661	$ 2,145	$ (2,347)	$ 4,088	$ 72,246

(a) Amount includes an $8.8 million reduction in the ARO liability due to the execution of a joint use agreement with a third party.

14. DISPOSITION PLANT SEVERANCE

Management retired several generation plants or units of plants during 2015. These plant closures resulted in involuntary severances. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

The disposition plant severance activity for the nine months ended September 30, 2015 is described in the following table:

Balance as of December 31, 2014	Expense Allocation from AEPSC	Incurred	Settled	Adjustments	Remaining Balance as of September 30, 2015
		(in thousands)			
$ 4,539	$ (2)	$ 24	$ (2,351) (a)	$ —	$ 2,210

(a) Settled includes amounts received from affiliates for expenses related to intercompany billing for operation and maintenance of affiliate plant.

KPCo recorded a charge of $4 million to Other Operation expense in December 2014 related to employees at the disposition plants. These expenses, net of adjustments, relate primarily to severance benefits and are included primarily in Other Operation expense on the condensed statements of income. The remaining liability is included in Other Current Liabilities on the condensed balance sheets. KPCo incurred additional charges during the second quarter of 2015 as severance plans were finalized after the plants were retired. Management does not expect additional severance costs to be incurred related to this initiative.

Kentucky Power Company

2016 First Quarter Report

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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	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AOCI	Accumulated Other Comprehensive Income.
ASU	Accounting Standards Update.
FASB	Financial Accounting Standards Board.
FERC	Federal Energy Regulatory Commission.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
OPEB	Other Postretirement Benefit Plans.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OTC	Over the counter.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PUCO	Public Utilities Commission of Ohio.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SSO	Standard service offer.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2016 and 2015
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2016	2015
REVENUES		
Electric Generation, Transmission and Distribution	$ 164,295	$ 199,900
Sales to AEP Affiliates	3,163	1,357
Other Revenues	213	192
TOTAL REVENUES	167,671	201,449
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	28,840	69,199
Purchased Electricity for Resale	13,815	11,796
Purchased Electricity from AEP Affiliates	19,462	23,557
Other Operation	19,970	20,331
Maintenance	17,677	18,289
Depreciation and Amortization	21,066	24,741
Taxes Other Than Income Taxes	5,810	5,604
TOTAL EXPENSES	126,640	173,517
OPERATING INCOME	41,031	27,932
Other Income (Expense):		
Other Income	329	85
Interest Expense	(11,244)	(11,037)
INCOME BEFORE INCOME TAX EXPENSE	30,116	16,980
Income Tax Expense	10,313	5,982
NET INCOME	$ 19,803	$ 10,998

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

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2016 and 2015
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015
Net Income	$ 19,803	$ 10,998
OTHER COMPREHENSIVE INCOME, NET OF TAXES		
Cash Flow Hedges, Net of Tax of $8 and $8 in 2016 and 2015, Respectively	15	15
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $2 and $9 in 2016 and 2015, Respectively	4	16
TOTAL OTHER COMPREHENSIVE INCOME	19	31
TOTAL COMPREHENSIVE INCOME	$ 19,822	$ 11,029

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2016 and 2015
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2014	$ 50,450	$ 517,460	$ 103,069	$ (7,336)	$ 663,643
Common Stock Dividends			(11,000)		(11,000)
Net Income			10,998		10,998
Other Comprehensive Income				31	31
Pension and OPEB Adjustment Related to Mitchell Plant				5,174	5,174
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2015	$ 50,450	$ 517,460	$ 103,067	$ (2,131)	$ 668,846
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2015	$ 50,450	$ 527,309	$ 86,960	$ (1,645)	$ 663,074
Common Stock Dividends			(11,000)		(11,000)
Net Income			19,803		19,803
Other Comprehensive Income				19	19
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2016	$ 50,450	$ 527,309	$ 95,763	$ (1,626)	$ 671,896

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
March 31, 2016 and December 31, 2015
(in thousands)
(Unaudited)

	March 31, 2016	December 31, 2015
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,371	$ 867
Accounts Receivable:		
Customers	14,516	13,747
Affiliated Companies	28,107	20,373
Accrued Unbilled Revenues	344	53
Miscellaneous	410	110
Allowance for Uncollectible Accounts	(261)	(243)
Total Accounts Receivable	43,116	34,040
Fuel	23,149	22,085
Materials and Supplies	16,439	26,705
Risk Management Assets – Nonaffiliated	2,279	2,869
Risk Management Assets – Affiliated	169	173
Accrued Tax Benefits	9,273	47,812
Prepayments and Other Current Assets	4,597	4,623
TOTAL CURRENT ASSETS	100,393	139,174
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,125,084	1,118,837
Transmission	570,716	568,963
Distribution	760,413	756,631
Other Property, Plant and Equipment	62,057	58,294
Construction Work in Progress	70,278	59,351
Total Property, Plant and Equipment	2,588,548	2,562,076
Accumulated Depreciation and Amortization	856,549	847,675
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,731,999	1,714,401
OTHER NONCURRENT ASSETS		
Regulatory Assets	562,963	557,956
Long-term Risk Management Assets – Nonaffiliated	80	12
Employee Benefits and Pension Assets	7,300	6,939
Deferred Charges and Other Noncurrent Assets	23,152	17,774
TOTAL OTHER NONCURRENT ASSETS	593,495	582,681
TOTAL ASSETS	$ 2,425,887	$ 2,436,256

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2016 and December 31, 2015
(Unaudited)

	March 31, 2016	December 31, 2015
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 15,790	$ 18,692
Accounts Payable:		
General	33,407	36,882
Affiliated Companies	20,456	25,139
Long-term Debt Due Within One Year – Nonaffiliated	65,000	65,000
Risk Management Liabilities – Nonaffiliated	1,189	1,002
Customer Deposits	26,764	26,916
Accrued Taxes	18,529	26,867
Accrued Interest	6,292	7,928
Regulatory Liability for Over-Recovered Fuel Costs	361	1,553
Other Current Liabilities	39,761	49,557
TOTAL CURRENT LIABILITIES	227,549	259,536
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	801,633	801,451
Long-term Risk Management Liabilities – Nonaffiliated	31	11
Deferred Income Taxes	648,623	636,158
Regulatory Liabilities and Deferred Investment Tax Credits	1,471	1,608
Asset Retirement Obligations	56,477	55,151
Employee Benefits and Pension Obligations	12,346	13,536
Deferred Credits and Other Noncurrent Liabilities	5,861	5,731
TOTAL NONCURRENT LIABILITIES	1,526,442	1,513,646
TOTAL LIABILITIES	1,753,991	1,773,182
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	527,309	527,309
Retained Earnings	95,763	86,960
Accumulated Other Comprehensive Income (Loss)	(1,626)	(1,645)
TOTAL COMMON SHAREHOLDER'S EQUITY	671,896	663,074
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 2,425,887	$ 2,436,256

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2016 and 2015
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015
OPERATING ACTIVITIES		
Net Income	$ 19,803	$ 10,998
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	21,066	24,741
Deferred Income Taxes	10,561	10,561
Allowance for Equity Funds Used During Construction	(405)	(66)
Mark-to-Market of Risk Management Contracts	733	2,533
Property Taxes	3,822	3,643
Fuel Over/Under-Recovery, Net	(1,192)	(5,992)
Provision for Refund	—	(6,578)
Change in Other Noncurrent Assets	(10,441)	(68)
Change in Other Noncurrent Liabilities	(416)	(1,417)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(9,076)	12,393
Fuel, Materials and Supplies	104	21,584
Accounts Payable	(7,594)	1,836
Accrued Taxes, Net	30,201	(6,859)
Accrued Interest	(1,636)	(1,682)
Other Current Assets	(806)	351
Other Current Liabilities	(9,111)	(8,964)
Net Cash Flows from Operating Activities	45,613	57,014
INVESTING ACTIVITIES		
Construction Expenditures	(31,687)	(26,169)
Other Investing Activities	555	231
Net Cash Flows Used for Investing Activities	(31,132)	(25,938)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	—	24,568
Change in Advances from Affiliates, Net	(2,902)	(44,388)
Principal Payments for Capital Lease Obligations	(229)	(292)
Dividends Paid on Common Stock	(11,000)	(11,000)
Other Financing Activities	154	76
Net Cash Flows Used for Financing Activities	(13,977)	(31,036)
Net Increase in Cash and Cash Equivalents	504	40
Cash and Cash Equivalents at Beginning of Period	867	795
Cash and Cash Equivalents at End of Period	$ 1,371	$ 835
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 12,621	$ 12,465
Net Cash Paid (Received) for Income Taxes	(38,806)	4
Noncash Acquisitions Under Capital Leases	402	120
Construction Expenditures Included in Current Liabilities as of March 31,	12,924	13,962

See Condensed Notes to Condensed Financial Statements beginning on page 8.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING MATTERS

General

The 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. Net income for the three months ended March 31, 2016 is not necessarily indicative of results that may be expected for the year ending December 31, 2016. The condensed financial statements are unaudited and should be read in conjunction with the audited 2015 financial statements and notes thereto, which are included in KPCo's 2015 Annual Report.

Management reviewed subsequent events through April 28, 2016, the date that the first quarter 2016 report was issued.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management reviews the new accounting literature to determine its relevance, if any, to KPCo's business. The following final pronouncements will impact the financial statements.

ASU 2014-09 "Revenue from Contracts with Customers" (ASU 2014-09)

In May 2014, the FASB issued ASU 2014-09 clarifying the method used to determine the timing and requirements for revenue recognition on the statements of income. Under the new standard, an entity must identify the performance obligations in a contract, determine the transaction price and allocate the price to specific performance obligations to recognize the revenue when the obligation is completed. The amendments in this update also require disclosure of sufficient information to allow users to understand the nature, amount, timing and uncertainty of revenue and cash flow arising from contracts.

The FASB deferred implementation of ASU 2014-09 under the terms in ASU 2015-14, "Revenue from Contracts with Customers (Topic: 606): Deferral of the Effective Date." The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017. Early adoption is permitted for annual periods beginning after December 15, 2016. As applicable, this standard may change the amount of revenue recognized on the statements of income in each reporting period. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on revenue or net income. Management plans to adopt ASU 2014-09 effective January 1, 2018.

ASU 2015-11 "Simplifying the Measurement of Inventory" (ASU 2015-11)

In July 2015, the FASB issued ASU 2015-11 simplifying the guidance on the subsequent measurement of inventory, excluding inventory measured using last-in, first-out or the retail inventory method. Under the new standard, inventory should be at the lower of cost and net realizable value. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016 with early adoption permitted. Management does not expect the new standard to impact KPCo's results of operations, financial position or cash flows. Management plans to adopt ASU 2015-11 prospectively, effective January 1, 2017.

ASU 2016-01 "Recognition and Measurement of Financial Assets and Financial Liabilities" (ASU 2016-01)

In January 2016, the FASB issued ASU 2016-01 enhancing the reporting model for financial instruments. Under the new standard, equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) are required to be measured at fair value with changes in fair value recognized in net income. The new standard also amends disclosure requirements and requires separate presentation of financial assets and liabilities by measurement category and form of financial asset (that is, securities or loans and receivables) on the balance sheet or the accompanying notes to the financial statements. The amendments also clarify that an entity should evaluate the need for a valuation allowance on a deferred tax asset related to available-for sale securities in combination with the entity's other deferred tax assets.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017 with early adoption permitted. The amendments will be applied by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. Management plans to adopt ASU 2016-01 effective January 1, 2018.

ASU 2016-02 "Accounting for Leases" (ASU 2016-02)

In February 2016, the FASB issued ASU 2016-02 increasing the transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. Under the new standard, an entity must recognize an asset and liability for operating leases on the balance sheets. Additionally, a capital lease will be known as a finance lease going forward. Leases with lease terms of 12 months or longer will be subject to the new requirements. Fundamentally, the criteria used to determine lease classification will remain the same, but will be more subjective under the new standard.

The new accounting guidance is effective for annual periods beginning after December 15, 2018 with early adoption permitted. The guidance will be applied by means of a modified retrospective approach. The modified retrospective approach will require lessees and lessors to recognize and measure leases at the beginning of the earliest period presented as well as a number of optional practical expedients that entities may elect to apply. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption. Management expects the new standard to impact KPCo's financial position, but not KPCo's results of operations or cash flows. Management plans to adopt ASU 2016-02 effective January 1, 2019.

ASU 2016-09 "Compensation – Stock Compensation" (ASU 2016-09)

In March 2016, the FASB issued ASU 2016-09 simplifying the accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities and classification on the statements of cash flows. Under the new standard, all excess tax benefits and tax deficiencies (including tax benefits of dividends on share-based payment awards) should be recognized as income tax expense or benefit on the statements of income. Under current GAAP, excess tax benefits are recognized in additional paid-in capital while tax deficiencies are recognized either as an offset to accumulated excess tax benefits, if any, or on the statements of income.

The new accounting guidance is effective for annual periods beginning after December 15, 2016. Early adoption is permitted in any interim or annual period. Certain provisions require retrospective/modified retrospective transition while others are to be applied prospectively. Management plans to adopt ASU 2016-09 effective January 1, 2017.

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI and details of reclassifications from AOCI for the three months ended March 31, 2016 and 2015. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 6 for additional details.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2016

	Cash Flow Hedges		
	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)		
Balance in AOCI as of December 31, 2015	$ (101)	$ (1,544)	$ (1,645)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	23	—	23
Amortization of Prior Service Cost (Credit)	—	(55)	(55)
Amortization of Actuarial (Gains)/Losses	—	62	62
Reclassifications from AOCI, before Income Tax (Expense) Credit	23	7	30
Income Tax (Expense) Credit	8	3	11
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	15	4	19
Net Current Period Other Comprehensive Income (Loss)	15	4	19
Balance in AOCI as of March 31, 2016	$ (86)	$ (1,540)	$ (1,626)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2015

	Cash Flow Hedges		
	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)		
Balance in AOCI as of December 31, 2014	$ (161)	$ (7,175)	$ (7,336)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	23	—	23
Amortization of Prior Service Cost (Credit)	—	(10)	(10)
Amortization of Actuarial (Gains)/Losses	—	35	35
Reclassifications from AOCI, before Income Tax (Expense) Credit	23	25	48
Income Tax (Expense) Credit	8	9	17
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	15	16	31
Net Current Period Other Comprehensive Income (Loss)	15	16	31
Pension and OPEB Adjustment Related to Mitchell Plant	—	5,174	5,174
Balance in AOCI as of March 31, 2015	$ (146)	$ (1,985)	$ (2,131)

4. RATE MATTERS

As discussed in KPCo's 2015 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo's 2015 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 2016 and updates KPCo's 2015 Annual Report.

Regulatory Assets Pending Final Regulatory Approval

Noncurrent Regulatory Assets	March 31, 2016	December 31, 2015
	(in thousands)	
Regulatory Assets Currently Not Earning a Return		
Storm Related Costs	$ 4,759	$ 4,377
Other Regulatory Assets Pending Final Regulatory Approval	12	—
Total Regulatory Assets Pending Final Regulatory Approval	$ 4,771	$ 4,377

If these costs are ultimately determined not to be recoverable, it could reduce future net income and cash flows and impact financial condition.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, KPCo's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against KPCo cannot be predicted. Management accrues contingent liabilities only when management concludes that it is both probable that a liability has been incurred at the date of the financial statements and the amount of loss can be reasonably estimated. When management determines that it is not probable, but rather reasonably possible that a liability has been incurred at the date of the financial statements, management discloses such contingencies and the possible loss or range of loss if such estimate can be made. Any estimated range is based on currently available information and involves elements of judgment and significant uncertainties. Any estimated range of possible loss may not represent the maximum possible loss exposure. Circumstances change over time and actual results may vary significantly from estimates.

For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements. The Commitments, Guarantees and Contingencies note within KPCo's 2015 Annual Report should be read in conjunction with this report.

GUARANTEES

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

Letter of Credit

KPCo has $65 million of variable rate Pollution Control Bonds supported by a bilateral letter of credit for $66 million. The letter of credit matures in June 2017.

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of March 31, 2016, there were no material liabilities recorded for any indemnifications.

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

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, KPCo is committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance. As of March 31, 2016, the maximum potential loss for these lease agreements was $1.6 million assuming the fair value of the equipment is zero at the end of the lease term.

6. BENEFIT PLANS

KPCo participates in an AEP sponsored qualified pension plan and an unfunded nonqualified pension plan. Substantially all of KPCo's employees are covered by the qualified plan or both the qualified and nonqualified pension plans. KPCo also participates in OPEB plans sponsored by AEP to provide health and life insurance benefits for retired employees.

Components of Net Periodic Benefit Cost

The following table provides the components of KPCo's net periodic benefit cost (credit) for the plans for the three months ended March 31, 2016 and 2015:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2016	2015	2016	2015
	(in thousands)			
Service Cost	$ 615	$ 670	$ 71	$ 86
Interest Cost	1,872	1,832	538	488
Expected Return on Plan Assets	(2,533)	(2,496)	(989)	(1,015)
Amortization of Prior Service Cost (Credit)	13	13	(606)	(606)
Amortization of Net Actuarial Loss	736	946	287	155
Net Periodic Benefit Cost (Credit)	$ 703	$ 965	$ (699)	$ (892)

7. BUSINESS SEGMENTS

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

8. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of KPCo.

KPCo is exposed to certain market risks as a major power producer and participant in the electricity, natural gas, coal and emission allowance markets. 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. Management utilizes derivative instruments to manage these risks.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

The strategy surrounding the use of derivative instruments primarily focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. The risk management strategies also include the use of derivative instruments for trading purposes which focus on seizing market opportunities to create value driven by expected changes in the market prices of the commodities. To accomplish these objectives, KPCo primarily employs risk management contracts including physical and financial forward purchase-and-sale contracts and, to a lesser extent, OTC swaps and options. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

KPCo utilizes power, capacity, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. KPCo utilizes interest rate derivative contracts in order to manage the interest rate exposure associated with its commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. KPCo also utilizes derivative contracts to manage 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 the Board of Directors.

The following table represents the gross notional volume of KPCo's outstanding derivative contracts as of March 31, 2016 and December 31, 2015:

Notional Volume of Derivative Instruments

Primary Risk Exposure	Volume March 31, 2016	Volume December 31, 2015	Unit of Measure
	(in thousands)		
Commodity:			
Power	5,019	7,864	MWhs
Natural Gas	52	64	MMBtus
Heating Oil and Gasoline	321	341	Gallons
Interest Rate	$ 243	$ 500	USD

Cash Flow Hedging Strategies

KPCo utilizes cash flow hedges on certain derivative transactions for the purchase and sale of power ("Commodity") in order to manage the variable price risk related to forecasted purchases and sales. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and purchases. KPCo does not hedge all commodity price risk.

KPCo utilizes a variety of interest rate derivative transactions in order to manage interest rate risk exposure. KPCo also utilizes interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. KPCo does not hedge all interest rate exposure.

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

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities on the condensed balance sheets 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 risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the March 31, 2016 and December 31, 2015 condensed balance sheets, KPCo had no netting of cash collateral received from third parties against short-term and long-term risk management assets and $54 thousand and $656 thousand, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following tables represent the gross fair value of KPCo's derivative activity on the condensed balance sheets as of March 31, 2016 and December 31, 2015:

Fair Value of Derivative Instruments
March 31, 2016

Balance Sheet Location	Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in thousands)	
Current Risk Management Assets - Nonaffiliated and Affiliated	$ 5,172	$ (2,724)	$ 2,448
Long-term Risk Management Assets - Nonaffiliated	227	(147)	80
Total Assets	5,399	(2,871)	2,528
Current Risk Management Liabilities - Nonaffiliated	3,967	(2,778)	1,189
Long-term Risk Management Liabilities - Nonaffiliated	178	(147)	31
Total Liabilities	4,145	(2,925)	1,220
Total MTM Derivative Contract Net Assets	$ 1,254	$ 54	$ 1,308

Fair Value of Derivative Instruments
December 31, 2015

Balance Sheet Location	Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in thousands)	
Current Risk Management Assets - Nonaffiliated and Affiliated	$ 5,017	$ (1,975)	$ 3,042
Long-term Risk Management Assets - Nonaffiliated	59	(47)	12
Total Assets	5,076	(2,022)	3,054
Current Risk Management Liabilities - Nonaffiliated	3,621	(2,619)	1,002
Long-term Risk Management Liabilities - Nonaffiliated	69	(58)	11
Total Liabilities	3,690	(2,677)	1,013
Total MTM Derivative Contract Net Assets	$ 1,386	$ 655	$ 2,041

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the condensed balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."
(c) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

The table below presents KPCo's activity of derivative risk management contracts for the three months ended March 31, 2016 and 2015:

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	Three Months Ended March 31, 2016	2015
	(in thousands)	
Electric Generation, Transmission and Distribution Revenues	$ (163)	$ 1,555
Sales to AEP Affiliates	290	—
Other Operation Expense	(25)	(31)
Maintenance Expense	(37)	(42)
Purchased Electricity for Resale	729	2,254
Fuel and Other Consumables Used for Electric Generation	—	(9)
Regulatory Assets (a)	42	(240)
Regulatory Liabilities (a)	189	(3,358)
Total Gain on Risk Management Contracts	$ 1,025	$ 129

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

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

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

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on KPCo's condensed statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on KPCo's condensed statements of income depending on the relevant facts and circumstances. Certain derivatives that economically hedge future commodity risk are recorded in the same expense line item on the condensed statements of income as that of the associated risk. However, unrealized and some realized gains and losses for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains), in accordance with the accounting guidance for "Regulated Operations."

In connection with OPCo's June 2012 - May 2015 ESP, the PUCO ordered OPCo to conduct energy and capacity auctions for its entire SSO load for delivery beginning in June 2015. These auctions resulted in a range of products, including 12-month, 24-month, and 36-month periods. The delivery period for each contract is scheduled to start on the first day of June of each year, immediately following the auction. Certain affiliated entities, including KPCo, participated in the auction process and were awarded tranches of OPCo's SSO load. The underlying contracts are derivatives subject to the accounting guidance for "Derivatives and Hedging" and are accounted for using MTM accounting, unless the contract has been designated as a normal purchase or normal sale.

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 would recognize any hedge ineffectiveness as a regulatory asset (for losses) or a regulatory liability (for gains) if applicable.

Realized gains and losses on derivative contracts for the purchase and sale of power designated as cash flow hedges are included in Total Revenues or Purchased Electricity for Resale on KPCo's condensed statements of income, or in Regulatory Assets or Regulatory Liabilities on KPCo's condensed balance sheets, depending on the specific nature of the risk being hedged. During the three months ended March 31, 2016 and 2015, KPCo did not designate power derivatives as cash flow hedges.

KPCo reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on its condensed balance sheets into Interest Expense on its condensed statements of income in those periods in which hedged interest payments occur. During the three months ended March 31, 2016 and 2015, KPCo did not apply cash flow hedging to outstanding interest rate derivatives.

During the three months ended March 31, 2016 and 2015, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

For details on effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's condensed balance sheets and the reasons for changes in cash flow hedges, see Note 3.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's condensed balance sheets as of March 31, 2016 and December 31, 2015 were:

Impact of Cash Flow Hedges on the Condensed Balance Sheets

	Interest Rate	
	March 31, 2016	**December 31, 2015**
	(in thousands)	
Hedging Assets (a)	$ —	$ —
Hedging Liabilities (a)	—	—
AOCI Loss Net of Tax	(86)	(101)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(60)	(60)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on KPCo's condensed balance sheets.

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of March 31, 2016, KPCo is not hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") its exposure to variability in future cash flows related to forecasted transactions.

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

Master agreements are typically used to facilitate the netting of cash flows associated with a single counterparty and may include collateral requirements. Collateral requirements in the form of cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. A counterparty is required 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, master agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, KPCo is obligated to post an additional amount of collateral if certain credit ratings decline below a specified rating threshold. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. KPCo has not experienced a downgrade below a specified rating threshold that would require the posting of additional collateral. There is no exposure relating to derivative contracts, however, there is exposure relating to RTOs, ISOs and non-derivative contracts. The following table represents KPCo's exposure if credit ratings were to decline below a specified rating threshold as of March 31, 2016 and December 31, 2015:

	March 31, 2016	December 31, 2015
	(in thousands)	
Amount of Collateral KPCo Would Have Been Required to Post Attributable to RTOs and ISOs	$ 439	$ 1,003
Amount of Collateral Attributable to Other Contracts	13	23

In addition, a majority of KPCo's non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation that is $50 million or greater. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering contractual netting arrangements as of March 31, 2016 and December 31, 2015:

	March 31, 2016	December 31, 2015
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 790	$ 750
Amount of Cash Collateral Posted	—	—
Additional Settlement Liability if Cross Default Provision is Triggered	790	750

9. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability. The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with established risk management policies as approved by the Finance Committee of AEP's Board of Directors. AEPSC's market risk oversight staff independently monitors risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (Regulated Risk Committee) various reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations and Chief Risk Officer.

For commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are nonbinding in nature but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A portion of the Level 3 instruments have been economically hedged which limits potential earnings volatility.

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of KPCo's Long-term Debt as of March 31, 2016 and December 31, 2015 are summarized in the following table:

	March 31, 2016		December 31, 2015	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 866,633	$ 984,807	$ 866,451	$ 963,639

Fair Value Measurements of Financial Assets and Liabilities

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, 2016 and December 31, 2015. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2016

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets – Nonaffiliated and Affiliated					
Risk Management Commodity Contracts (a) (b)	$ 32	$ 3,530	$ 1,722	$ (2,756)	$ 2,528
Liabilities:					
Risk Management Liabilities – Nonaffiliated					
Risk Management Commodity Contracts (a) (b)	$ 31	$ 3,647	$ 352	$ (2,810)	$ 1,220

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2015

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets – Nonaffiliated and Affiliated					
Risk Management Commodity Contracts (a) (b)	$ 36	$ 2,692	$ 2,338	$ (2,012)	$ 3,054
Liabilities:					
Risk Management Liabilities – Nonaffiliated					
Risk Management Commodity Contracts (a) (b)	$ 43	$ 3,545	$ 92	$ (2,667)	$ 1,013

(a) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(b) Substantially comprised of power contracts.

There were no transfers between Level 1 and Level 2 during the three months ended March 31, 2016 and 2015.

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, 2016	Net Risk Management Assets (Liabilities) (a) (in thousands)
Balance as of December 31, 2015	$ 2,246
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	382
Purchases, Issuances and Settlements (d)	(1,739)
Transfers out of Level 3 (e) (f)	22
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	459
Balance as of March 31, 2016	$ 1,370

Three Months Ended March 31, 2015	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of December 31, 2014	$ 3,927
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	467
Purchases, Issuances and Settlements (d)	(2,791)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	67
Balance as of March 31, 2015	$ 1,670

(a) Includes both affiliated and nonaffiliated transactions.
(b) Included in revenues on KPCo's condensed statements of income.
(c) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(d) Represents the settlement of risk management commodity contracts for the reporting period.
(e) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(f) Represents existing assets or liabilities that were previously categorized as Level 3.
(g) 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.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions as of March 31, 2016 and December 31, 2015:

Significant Unobservable Inputs
March 31, 2016

	Fair Value		Valuation	Significant Unobservable	Forward Price Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$ 1,682	$ 33	Discounted Cash Flow	Forward Market Price	$ 8.77	$ 47.05	$ 29.14
FTRs	40	319	Discounted Cash Flow	Forward Market Price	0.25	5.58	0.80
Total	$ 1,722	$ 352					

Significant Unobservable Inputs
December 31, 2015

	Fair Value		Valuation	Significant Unobservable	Forward Price Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$ 1,580	$ 37	Discounted Cash Flow	Forward Market Price	$ 12.61	$ 47.24	$ 32.38
FTRs	758	55	Discounted Cash Flow	Forward Market Price	(6.96)	8.43	1.34
Total	$ 2,338	$ 92					

(a) Represents market prices in dollars per MWh.

The following table provides sensitivity of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts and FTRs as of March 31, 2016 and December 31, 2015:

Sensitivity of Fair Value Measurements

Significant Unobservable Input	Position	Change in Input	Impact on Fair Value Measurement
Forward Market Price	Buy	Increase (Decrease)	Higher (Lower)
Forward Market Price	Sell	Increase (Decrease)	Lower (Higher)

10. INCOME TAXES

AEP System Tax Allocation Agreement

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

Federal and State Income Tax Audit Status

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2011. The IRS examination of years 2011, 2012 and 2013 started in April 2014. KPCo and other AEP subsidiaries received a Revenue Agents Report in April 2016, completing the 2011 through 2013 audit cycle indicating an agreed upon audit. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to materially impact net income.

KPCo and other AEP subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns. KPCo and other AEP subsidiaries are currently under examination in several state and local jurisdictions. However, it is possible that previously filed tax returns have positions that may be challenged by these tax authorities. Management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income. KPCo is no longer subject to state or local income tax examinations by tax authorities for years before 2009.

11. FINANCING ACTIVITIES

Long-term Debt

KPCo did not have any long-term debt issuances or retirements during the first three months of 2016.

Dividend Restrictions

KPCo pays dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of KPCo to transfer funds to Parent in the form of dividends.

Federal Power Act

The Federal Power Act prohibits KPCo from participating "in the making or paying of any dividends of such public utility from any funds properly included in capital account." This restriction does not limit the ability of KPCo to pay dividends out of retained earnings.

Leverage Restrictions

Pursuant to the credit agreement leverage restrictions, KPCo must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%.

Corporate Borrowing Program – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding borrowings from the Utility Money Pool as of March 31, 2016 and December 31, 2015 are included in Advances from Affiliates on KPCo's condensed balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the three months ended March 31, 2016 are described in the following table:

Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Borrowings from the Utility Money Pool as of March 31, 2016	Authorized Short-Term Borrowing Limit
		(in thousands)			
$ 39,102	$ —	$ 20,873	$ —	$ 15,790	$ 225,000

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, 2016 and 2015 are summarized in the following table:

Three Months Ended March 31,	Maximum Interest Rate for Funds Borrowed from the Utility Money Pool	Minimum Interest Rate for Funds Borrowed from the Utility Money Pool	Maximum Interest Rate for Funds Loaned to the Utility Money Pool	Minimum Interest Rate 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
2016	0.83%	0.69%	—%	—%	0.73%	—%
2015	0.59%	0.39%	—%	—%	0.47%	—%

Sale of Receivables – AEP Credit

Under a sale of receivables arrangement, KPCo sells, without recourse, certain of its customer accounts receivable and accrued unbilled revenue balances to AEP Credit and is charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for KPCo's receivables. The costs of customer accounts receivable sold are reported in Other Operation expense on KPCo's condensed statements of income. KPCo manages and services its accounts receivable sold.

AEP Credit's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables and expires in June 2017.

KPCo's amounts of accounts receivable and accrued unbilled revenues sold under the sale of receivables agreement were $42 million and $38 million as of March 31, 2016 and December 31, 2015, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold were $736 thousand and $840 thousand for the three months ended March 31, 2016 and 2015, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit were $155 million and $155 million for the three months ended March 31, 2016 and 2015, respectively.

12. VARIABLE INTEREST ENTITIES

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether KPCo is the primary beneficiary of a VIE, management considers factors such as equity at risk, the amount of the VIE's variability KPCo absorbs, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE, variable interests held by related parties and other factors. Management believes that significant assumptions and judgments were applied consistently. KPCo is not the primary beneficiary of any VIE and has not provided financial or other support to any VIE that was not previously contractually required.

AEPSC provides certain managerial and professional services to AEP's subsidiaries. Parent is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. KPCo's total billings from AEPSC for the three months ended March 31, 2016 and 2015 were $16 million and $13.2 million, respectively. The carrying amount of liabilities associated with AEPSC as of March 31, 2016 and December 31, 2015 was $5.2 million and $7.7 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of Parent, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant, Unit 1 and leases a 50% interest in Rockport Plant, Unit 2. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP has agreed to provide AEGCo with the funds necessary to satisfy all of the debt obligations of AEGCo. KPCo is considered to have a significant interest in AEGCo due to these transactions. KPCo is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. Due to AEP management's control over AEGCo, KPCo is not considered the primary beneficiary of AEGCo. In the event AEGCo would require financing or other support outside the billings to KPCo, this financing would be provided by AEP. Total billings from AEGCo for the three months ended March 31, 2016 and 2015 were $19.5 million and $23.6 million, respectively. The carrying amount of liabilities associated with AEGCo as of March 31, 2016 and December 31, 2015 was $4.8 million and $7.7 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

Kentucky Power Company

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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	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AOCI	Accumulated Other Comprehensive Income.
ASU	Accounting Standards Update.
ESP	Electric Security Plans, a PUCO requirement for electric utilities to adjust their rates by filing with the PUCO.
FASB	Financial Accounting Standards Board.
FERC	Federal Energy Regulatory Commission.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PUCO	Public Utilities Commission of Ohio.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SSO	Standard service offer.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2016 and 2015
(in thousands)
(Unaudited)

	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
REVENUES				
Electric Generation, Transmission and Distribution	$ 144,318	$ 148,503	$ 308,613	$ 348,403
Sales to AEP Affiliates	1,658	2,577	4,821	3,934
Other Revenues	224	196	437	388
TOTAL REVENUES	146,200	151,276	313,871	352,725
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	23,805	37,586	52,645	106,785
Purchased Electricity for Resale	11,146	6,165	24,961	17,961
Purchased Electricity from AEP Affiliates	24,001	25,711	43,463	49,268
Other Operation	22,873	19,749	42,843	40,080
Maintenance	16,767	18,896	34,444	37,185
Depreciation and Amortization	20,275	23,508	41,341	48,249
Taxes Other Than Income Taxes	5,215	5,395	11,025	10,999
TOTAL EXPENSES	124,082	137,010	250,722	310,527
OPERATING INCOME	22,118	14,266	63,149	42,198
Other Income (Expense):				
Interest Income	443	93	367	112
Allowance for Equity Funds Used During Construction	282	388	687	454
Interest Expense	(11,056)	(11,183)	(22,300)	(22,220)
INCOME BEFORE INCOME TAX EXPENSE	11,787	3,564	41,903	20,544
Income Tax Expense	2,900	1,256	13,213	7,238
NET INCOME	$ 8,887	$ 2,308	$ 28,690	$ 13,306

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

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2016 and 2015
(in thousands)
(Unaudited)

	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Net Income	$ 8,887	$ 2,308	$ 28,690	$ 13,306
OTHER COMPREHENSIVE INCOME, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $8 and $8 for the Three Months Ended June 30, 2016 and 2015, Respectively, and $16 and $16 for the Six Months Ended June 30, 2016 and 2015, Respectively	15	15	30	30
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $3 and $9 for the Three Months Ended June 30, 2016 and 2015, Respectively, and $5 and $18 for the Six Months Ended June 30, 2016 and 2015, Respectively	5	17	9	33
TOTAL OTHER COMPREHENSIVE INCOME	20	32	39	63
TOTAL COMPREHENSIVE INCOME	$ 8,907	$ 2,340	$ 28,729	$ 13,369

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 30, 2016 and 2015
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2014	$ 50,450	$ 517,460	$ 103,069	$ (7,336)	$ 663,643
Common Stock Dividends			(22,000)		(22,000)
Net Income			13,306		13,306
Other Comprehensive Income				63	63
Pension and OPEB Adjustment Related to Mitchell Plant				5,174	5,174
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2015	$ 50,450	$ 517,460	$ 94,375	$ (2,099)	$ 660,186
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2015	$ 50,450	$ 527,309	$ 86,960	$ (1,645)	$ 663,074
Common Stock Dividends			(22,000)		(22,000)
Net Income			28,690		28,690
Other Comprehensive Income				39	39
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2016	$ 50,450	$ 527,309	$ 93,650	$ (1,606)	$ 669,803

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
June 30, 2016 and December 31, 2015
(in thousands)
(Unaudited)

	June 30, 2016	December 31, 2015
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,053	$ 867
Accounts Receivable:		
Customers	14,656	13,747
Affiliated Companies	19,867	20,373
Accrued Unbilled Revenues	2,078	53
Miscellaneous	2,324	110
Allowance for Uncollectible Accounts	(69)	(243)
Total Accounts Receivable	38,856	34,040
Fuel	21,317	22,085
Materials and Supplies	16,359	26,705
Risk Management Assets – Nonaffiliated	1,016	2,869
Risk Management Assets – Affiliated	15	173
Accrued Tax Benefits	10,953	47,812
Prepayments and Other Current Assets	4,366	4,623
TOTAL CURRENT ASSETS	93,935	139,174
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,185,691	1,118,837
Transmission	571,523	568,963
Distribution	769,764	756,631
Other Property, Plant and Equipment	63,081	58,294
Construction Work in Progress	19,252	59,351
Total Property, Plant and Equipment	2,609,311	2,562,076
Accumulated Depreciation and Amortization	865,326	847,675
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,743,985	1,714,401
OTHER NONCURRENT ASSETS		
Regulatory Assets	563,047	557,956
Long-term Risk Management Assets – Nonaffiliated	61	12
Employee Benefits and Pension Assets	7,680	6,939
Deferred Charges and Other Noncurrent Assets	19,503	17,774
TOTAL OTHER NONCURRENT ASSETS	590,291	582,681
TOTAL ASSETS	$ 2,428,211	$ 2,436,256

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
June 30, 2016 and December 31, 2015
(Unaudited)

	June 30, 2016	December 31, 2015
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 16,274	$ 18,692
Accounts Payable:		
General	31,361	36,882
Affiliated Companies	25,694	25,139
Long-term Debt Due Within One Year – Nonaffiliated	65,000	65,000
Risk Management Liabilities – Nonaffiliated	896	1,002
Customer Deposits	26,732	26,916
Accrued Taxes	18,033	26,867
Accrued Interest	8,050	7,928
Regulatory Liability for Over-Recovered Fuel Costs	—	1,553
Other Current Liabilities	39,619	49,557
TOTAL CURRENT LIABILITIES	231,659	259,536
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	801,809	801,451
Long-term Risk Management Liabilities – Nonaffiliated	47	11
Deferred Income Taxes	653,525	636,158
Regulatory Liabilities and Deferred Investment Tax Credits	147	1,608
Asset Retirement Obligations	54,862	55,151
Employee Benefits and Pension Obligations	10,726	13,536
Deferred Credits and Other Noncurrent Liabilities	5,633	5,731
TOTAL NONCURRENT LIABILITIES	1,526,749	1,513,646
TOTAL LIABILITIES	1,758,408	1,773,182
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	527,309	527,309
Retained Earnings	93,650	86,960
Accumulated Other Comprehensive Income (Loss)	(1,606)	(1,645)
TOTAL COMMON SHAREHOLDER'S EQUITY	669,803	663,074
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 2,428,211	$ 2,436,256

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2016 and 2015
(in thousands)
(Unaudited)

	Six Months Ended June 30, 2016	2015
OPERATING ACTIVITIES		
Net Income	$ 28,690	$ 13,306
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	41,341	48,249
Deferred Income Taxes	14,711	43,286
Allowance for Equity Funds Used During Construction	(687)	(454)
Mark-to-Market of Risk Management Contracts	1,894	(1,059)
Pension Contributions to Qualified Plan Trust	(1,509)	(1,900)
Property Taxes	7,681	7,164
Fuel Over/Under-Recovery, Net	(1,951)	(3,977)
Provision for Refund	—	(13,155)
Change in Other Noncurrent Assets	(17,535)	(6,868)
Change in Other Noncurrent Liabilities	(1,620)	2,551
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(4,816)	16,543
Fuel, Materials and Supplies	2,310	26,667
Accounts Payable	486	(7,872)
Accrued Taxes, Net	27,997	(38,699)
Other Current Assets	(177)	638
Other Current Liabilities	(8,746)	(9,815)
Net Cash Flows from Operating Activities	88,069	74,605
INVESTING ACTIVITIES		
Construction Expenditures	(63,964)	(59,866)
Other Investing Activities	810	861
Net Cash Flows Used for Investing Activities	(63,154)	(59,005)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	—	24,546
Change in Advances from Affiliates, Net	(2,418)	(17,952)
Principal Payments for Capital Lease Obligations	(476)	(550)
Dividends Paid on Common Stock	(22,000)	(22,000)
Other Financing Activities	165	76
Net Cash Flows Used for Financing Activities	(24,729)	(15,880)
Net Increase (Decrease) in Cash and Cash Equivalents	186	(280)
Cash and Cash Equivalents at Beginning of Period	867	795
Cash and Cash Equivalents at End of Period	$ 1,053	$ 515
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 21,733	$ 21,718
Net Cash Paid (Received) for Income Taxes	(36,639)	106
Noncash Acquisitions Under Capital Leases	470	132
Construction Expenditures Included in Current Liabilities as of June 30,	7,723	11,081

See Condensed Notes to Condensed Financial Statements beginning on page 8.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING MATTERS

General

The 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. Net income for the three and six months ended June 30, 2016 is not necessarily indicative of results that may be expected for the year ending December 31, 2016. The condensed financial statements are unaudited and should be read in conjunction with the audited 2015 financial statements and notes thereto, which are included in KPCo's 2015 Annual Report.

Management reviewed subsequent events through July 28, 2016, the date that the second quarter 2016 report was issued.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management reviews the new accounting literature to determine its relevance, if any, to KPCo's business. The following final pronouncements will impact the financial statements.

ASU 2014-09 "Revenue from Contracts with Customers" (ASU 2014-09)

In May 2014, the FASB issued ASU 2014-09 clarifying the method used to determine the timing and requirements for revenue recognition on the statements of income. Under the new standard, an entity must identify the performance obligations in a contract, determine the transaction price and allocate the price to specific performance obligations to recognize the revenue when the obligation is completed. The amendments in this update also require disclosure of sufficient information to allow users to understand the nature, amount, timing and uncertainty of revenue and cash flow arising from contracts.

The FASB deferred implementation of ASU 2014-09 under the terms in ASU 2015-14, "Revenue from Contracts with Customers (Topic: 606): Deferral of the Effective Date." The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017. Early adoption is permitted for annual periods beginning after December 15, 2016. As applicable, this standard may change the amount of revenue recognized on the statements of income in each reporting period. Management is analyzing the impact of this new standard and the related ASUs that clarify guidance in the standard. At this time, management cannot estimate the impact of adoption on revenue or net income. Management plans to adopt ASU 2014-09 effective January 1, 2018.

ASU 2015-11 "Simplifying the Measurement of Inventory" (ASU 2015-11)

In July 2015, the FASB issued ASU 2015-11 simplifying the guidance on the subsequent measurement of inventory, excluding inventory measured using last-in, first-out or the retail inventory method. Under the new standard, inventory should be at the lower of cost and net realizable value. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016 with early adoption permitted. Management does not expect the new standard to impact KPCo's results of operations, financial position or cash flows. Management plans to adopt ASU 2015-11 prospectively, effective January 1, 2017.

ASU 2016-01 "Recognition and Measurement of Financial Assets and Financial Liabilities" (ASU 2016-01)

In January 2016, the FASB issued ASU 2016-01 enhancing the reporting model for financial instruments. Under the new standard, equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) are required to be measured at fair value with changes in fair value recognized in net income. The new standard also amends disclosure requirements and requires separate presentation of financial assets and liabilities by measurement category and form of financial asset (that is, securities or loans and receivables) on the balance sheet or the accompanying notes to the financial statements. The amendments also clarify that an entity should evaluate the need for a valuation allowance on a deferred tax asset related to available-for sale securities in combination with the entity's other deferred tax assets.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017 with early adoption permitted. The amendments will be applied by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. Management plans to adopt ASU 2016-01 effective January 1, 2018.

ASU 2016-02 "Accounting for Leases" (ASU 2016-02)

In February 2016, the FASB issued ASU 2016-02 increasing the transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. Under the new standard, an entity must recognize an asset and liability for operating leases on the balance sheets. Additionally, a capital lease will be known as a finance lease going forward. Leases with lease terms of 12 months or longer will be subject to the new requirements. Fundamentally, the criteria used to determine lease classification will remain the same, but will be more subjective under the new standard.

The new accounting guidance is effective for annual periods beginning after December 15, 2018 with early adoption permitted. The guidance will be applied by means of a modified retrospective approach. The modified retrospective approach will require lessees and lessors to recognize and measure leases at the beginning of the earliest period presented as well as a number of optional practical expedients that entities may elect to apply. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption. Management expects the new standard to impact KPCo's financial position, but not KPCo's results of operations or cash flows. Management plans to adopt ASU 2016-02 effective January 1, 2019.

ASU 2016-09 "Compensation – Stock Compensation" (ASU 2016-09)

In March 2016, the FASB issued ASU 2016-09 simplifying the accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities and classification on the statements of cash flows. Under the new standard, all excess tax benefits and tax deficiencies (including tax benefits of dividends on share-based payment awards) should be recognized as income tax expense or benefit on the statements of income. Under current GAAP, excess tax benefits are recognized in additional paid-in capital while tax deficiencies are recognized either as an offset to accumulated excess tax benefits, if any, or on the statements of income.

The new accounting guidance is effective for annual periods beginning after December 15, 2016. Early adoption is permitted in any interim or annual period. Certain provisions require retrospective/modified retrospective transition while others are to be applied prospectively. Management plans to adopt ASU 2016-09 effective January 1, 2017.

ASU 2016-13 "Measurement of Credit Losses on Financial Instruments" (ASU 2016-13)

In June 2016, the FASB issued ASU 2016-13 requiring an allowance to be recorded for all expected credit losses for financial assets. The allowance for credit losses is based on historical information, current conditions and reasonable and supportable forecasts. The new standard also makes revisions to the other than temporary impairment model for available-for-sale debt securities. Disclosures of credit quality indicators in relation to the amortized cost of financing receivables are further disaggregated by year of origination.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2019 with early adoption permitted for interim and annual periods beginning after December 15, 2018. The amendments will be applied through a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. Management plans to adopt ASU 2016-13 effective January 1, 2020.

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI and details of reclassifications from AOCI for the three and six months ended June 30, 2016 and 2015. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 6 for additional details.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended June 30, 2016

	Cash Flow Hedges		
	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)		
Balance in AOCI as of March 31, 2016	$ (86)	$ (1,540)	$ (1,626)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	23	—	23
Amortization of Prior Service Cost (Credit)	—	(56)	(56)
Amortization of Actuarial (Gains)/Losses	—	62	62
Reclassifications from AOCI, before Income Tax (Expense) Credit	23	6	29
Income Tax (Expense) Credit	8	1	9
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	15	5	20
Net Current Period Other Comprehensive Income (Loss)	15	5	20
Balance in AOCI as of June 30, 2016	$ (71)	$ (1,535)	$ (1,606)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended June 30, 2015

	Cash Flow Hedges		
	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)		
Balance in AOCI as of March 31, 2015	$ (146)	$ (1,985)	$ (2,131)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	23	—	23
Amortization of Prior Service Cost (Credit)	—	(10)	(10)
Amortization of Actuarial (Gains)/Losses	—	36	36
Reclassifications from AOCI, before Income Tax (Expense) Credit	23	26	49
Income Tax (Expense) Credit	8	9	17
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	15	17	32
Net Current Period Other Comprehensive Income (Loss)	15	17	32
Balance in AOCI as of June 30, 2015	$ (131)	$ (1,968)	$ (2,099)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Six Months Ended June 30, 2016

	Cash Flow Hedges		
	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)		
Balance in AOCI as of December 31, 2015	$ (101)	$ (1,544)	$ (1,645)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	46	—	46
Amortization of Prior Service Cost (Credit)	—	(111)	(111)
Amortization of Actuarial (Gains)/Losses	—	124	124
Reclassifications from AOCI, before Income Tax (Expense) Credit	46	13	59
Income Tax (Expense) Credit	16	4	20
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	30	9	39
Net Current Period Other Comprehensive Income (Loss)	30	9	39
Balance in AOCI as of June 30, 2016	$ (71)	$ (1,535)	$ (1,606)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Six Months Ended June 30, 2015

	Cash Flow Hedges		
	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)		
Balance in AOCI as of December 31, 2014	$ (161)	$ (7,175)	$ (7,336)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	46	—	46
Amortization of Prior Service Cost (Credit)	—	(20)	(20)
Amortization of Actuarial (Gains)/Losses	—	71	71
Reclassifications from AOCI, before Income Tax (Expense) Credit	46	51	97
Income Tax (Expense) Credit	16	18	34
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	30	33	63
Net Current Period Other Comprehensive Income (Loss)	30	33	63
Pension and OPEB Adjustment Related to Mitchell Plant	—	5,174	5,174
Balance in AOCI as of June 30, 2015	$ (131)	$ (1,968)	$ (2,099)

4. RATE MATTERS

As discussed in KPCo's 2015 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo's 2015 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 2016 and updates KPCo's 2015 Annual Report.

Regulatory Assets Pending Final Regulatory Approval

Noncurrent Regulatory Assets	June 30, 2016	December 31, 2015
	(in thousands)	
Regulatory Assets Currently Not Earning a Return		
Storm Related Costs	$ 4,759	$ 4,377
Other Regulatory Assets Pending Final Regulatory Approval	621	—
Total Regulatory Assets Pending Final Regulatory Approval	$ 5,380	$ 4,377

If these costs are ultimately determined not to be recoverable, it could reduce future net income and cash flows and impact financial condition.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, KPCo's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against KPCo cannot be predicted. Management accrues contingent liabilities only when management concludes that it is both probable that a liability has been incurred at the date of the financial statements and the amount of loss can be reasonably estimated. When management determines that it is not probable, but rather reasonably possible that a liability has been incurred at the date of the financial statements, management discloses such contingencies and the possible loss or range of loss if such estimate can be made. Any estimated range is based on currently available information and involves elements of judgment and significant uncertainties. Any estimated range of possible loss may not represent the maximum possible loss exposure. Circumstances change over time and actual results may vary significantly from estimates.

For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements. The Commitments, Guarantees and Contingencies note within KPCo's 2015 Annual Report should be read in conjunction with this report.

GUARANTEES

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

Letter of Credit

KPCo has $65 million of variable rate Pollution Control Bonds supported by a bilateral letter of credit for $66 million. The letter of credit matures in June 2017.

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of June 30, 2016, there were no material liabilities recorded for any indemnifications.

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

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, KPCo is committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance. As of June 30, 2016, the maximum potential loss for these lease agreements was $1.6 million assuming the fair value of the equipment is zero at the end of the lease term.

6. BENEFIT PLANS

KPCo participates in an AEP sponsored qualified pension plan and an unfunded nonqualified pension plan. Substantially all of KPCo's employees are covered by the qualified plan or both the qualified and nonqualified pension plans. KPCo also participates in OPEB plans sponsored by AEP to provide health and life insurance benefits for retired employees.

Components of Net Periodic Benefit Cost

The following tables provide the components of KPCo's net periodic benefit cost (credit) for the plans for the three and six months ended June 30, 2016 and 2015:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2016	2015	2016	2015
	(in thousands)			
Service Cost	$ 615	$ 670	$ 70	$ 86
Interest Cost	1,873	1,831	537	488
Expected Return on Plan Assets	(2,533)	(2,495)	(988)	(1,015)
Amortization of Prior Service Cost (Credit)	13	13	(606)	(606)
Amortization of Net Actuarial Loss	735	947	288	156
Net Periodic Benefit Cost (Credit)	$ 703	$ 966	$ (699)	$ (891)

	Pension Plans		Other Postretirement Benefit Plans	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in thousands)			
Service Cost	$ 1,230	$ 1,340	$ 141	$ 172
Interest Cost	3,745	3,663	1,075	976
Expected Return on Plan Assets	(5,066)	(4,991)	(1,977)	(2,030)
Amortization of Prior Service Cost (Credit)	26	26	(1,212)	(1,212)
Amortization of Net Actuarial Loss	1,471	1,893	575	311
Net Periodic Benefit Cost (Credit)	$ 1,406	$ 1,931	$ (1,398)	$ (1,783)

7. BUSINESS SEGMENTS

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

8. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of KPCo.

KPCo is exposed to certain market risks as a major power producer and participant in the electricity, natural gas, coal and emission allowance markets. 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. Management utilizes derivative instruments to manage these risks.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

The strategy surrounding the use of derivative instruments primarily focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. The risk management strategies also include the use of derivative instruments for trading purposes which focus on seizing market opportunities to create value driven by expected changes in the market prices of the commodities. To accomplish these objectives, KPCo primarily employs risk management contracts including physical and financial forward purchase-and-sale contracts and, to a lesser extent, OTC swaps and options. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

KPCo utilizes power, capacity, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. KPCo utilizes interest rate derivative contracts in order to manage the interest rate exposure associated with its commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. KPCo also utilizes derivative contracts to manage 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 the Board of Directors.

The following table represents the gross notional volume of KPCo's outstanding derivative contracts as of June 30, 2016 and December 31, 2015:

Notional Volume of Derivative Instruments

Primary Risk Exposure	Volume: June 30, 2016	Volume: December 31, 2015	Unit of Measure
	(in thousands)		
Commodity:			
Power	17,649	7,864	MWhs
Natural Gas	40	64	MMBtus
Heating Oil and Gasoline	410	341	Gallons
Interest Rate	$ 243	$ 500	USD

Cash Flow Hedging Strategies

KPCo utilizes cash flow hedges on certain derivative transactions for the purchase and sale of power ("Commodity") in order to manage the variable price risk related to forecasted purchases and sales. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and purchases. KPCo does not hedge all commodity price risk.

KPCo utilizes a variety of interest rate derivative transactions in order to manage interest rate risk exposure. KPCo also utilizes interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. KPCo does not hedge all interest rate exposure.

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

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities on the balance sheets 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 risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the June 30, 2016 and December 31, 2015 balance sheets, KPCo netted $76 thousand and $0, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $209 thousand and $656 thousand, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following tables represent the gross fair value of KPCo's derivative activity on the balance sheets as of June 30, 2016 and December 31, 2015:

Fair Value of Derivative Instruments
June 30, 2016

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in thousands)	
Current Risk Management Assets - Nonaffiliated and Affiliated	$ 4,300	$ (3,269)	$ 1,031
Long-term Risk Management Assets - Nonaffiliated	142	(81)	61
Total Assets	4,442	(3,350)	1,092
Current Risk Management Liabilities - Nonaffiliated	4,298	(3,402)	896
Long-term Risk Management Liabilities - Nonaffiliated	128	(81)	47
Total Liabilities	4,426	(3,483)	943
Total MTM Derivative Contract Net Assets	$ 16	$ 133	$ 149

Fair Value of Derivative Instruments
December 31, 2015

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in thousands)	
Current Risk Management Assets - Nonaffiliated and Affiliated	$ 5,017	$ (1,975)	$ 3,042
Long-term Risk Management Assets - Nonaffiliated	59	(47)	12
Total Assets	5,076	(2,022)	3,054
Current Risk Management Liabilities - Nonaffiliated	3,621	(2,619)	1,002
Long-term Risk Management Liabilities - Nonaffiliated	69	(58)	11
Total Liabilities	3,690	(2,677)	1,013
Total MTM Derivative Contract Net Assets	$ 1,386	$ 655	$ 2,041

(a) Derivative instruments within this category are reported gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."
(c) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

The table below presents KPCo's activity of derivative risk management contracts for the three and six months ended June 30, 2016 and 2015:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three and Six Months Ended June 30, 2016 and 2015

Location of Gain (Loss)	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
	(in thousands)			
Electric Generation, Transmission and Distribution Revenues	$ 111	$ 310	$ (52)	$ 2,157
Sales to AEP Affiliates	139	249	429	249
Other Operation Expense	(8)	(21)	(33)	(52)
Maintenance Expense	(20)	(29)	(57)	(71)
Purchased Electricity for Resale	710	319	1,439	2,573
Fuel and Other Consumables Used for Electric Generation	—	(4)	—	(13)
Regulatory Assets (a)	103	(301)	145	(267)
Regulatory Liabilities (a)	(633)	4,176	(444)	545
Total Gain on Risk Management Contracts	$ 402	$ 4,699	$ 1,427	$ 5,121

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

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

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

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on KPCo's statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on KPCo's statements of income depending on the relevant facts and circumstances. Certain derivatives that economically hedge future commodity risk are recorded in the same expense line item on the statements of income as that of the associated risk. However, unrealized and some realized gains and losses for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains), in accordance with the accounting guidance for "Regulated Operations."

In connection with OPCo's June 2012 - May 2015 ESP, the PUCO ordered OPCo to conduct energy and capacity auctions for its entire SSO load for delivery beginning in June 2015. These auctions resulted in a range of products, including 12-month, 24-month, and 36-month periods. The delivery period for each contract is scheduled to start on the first day of June of each year, immediately following the auction. Certain affiliated entities, including KPCo, participated in the auction process and were awarded tranches of OPCo's SSO load. The underlying contracts are derivatives subject to the accounting guidance for "Derivatives and Hedging" and are accounted for using MTM accounting, unless the contract has been designated as a normal purchase or normal sale.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), KPCo initially reports the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the balance sheets until the period the hedged item affects Net Income. KPCo would recognize any hedge ineffectiveness as a regulatory asset (for losses) or a regulatory liability (for gains) if applicable.

Realized gains and losses on derivative contracts for the purchase and sale of power designated as cash flow hedges are included in Total Revenues or Purchased Electricity for Resale on KPCo's statements of income, or in Regulatory Assets or Regulatory Liabilities on KPCo's balance sheets, depending on the specific nature of the risk being hedged. During the three and six months ended June 30, 2016 and 2015, KPCo did not designate power derivatives as cash flow hedges.

KPCo reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on its balance sheets into Interest Expense on its statements of income in those periods in which hedged interest payments occur. During the three and six months ended June 30, 2016 and 2015, KPCo did not apply cash flow hedging to outstanding interest rate derivatives.

During the three and six months ended June 30, 2016 and 2015, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

For details on effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's balance sheets and the reasons for changes in cash flow hedges, see Note 3.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's balance sheets as of June 30, 2016 and December 31, 2015 were:

Impact of Cash Flow Hedges on the Condensed Balance Sheet

	Interest Rate	
	June 30, 2016	December 31, 2015
	(in thousands)	
AOCI Loss Net of Tax	$ (71)	$ (101)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(60)	(60)

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 June 30, 2016, KPCo is not hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") its exposure to variability in future cash flows related to forecasted transactions.

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

Master agreements are typically used to facilitate the netting of cash flows associated with a single counterparty and may include collateral requirements. Collateral requirements in the form of cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. A counterparty is required 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, master agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, KPCo is obligated to post an additional amount of collateral if certain credit ratings decline below a specified rating threshold. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. KPCo has not experienced a downgrade below a specified rating threshold that would require the posting of additional collateral. There is no exposure relating to derivative contracts, however, there is exposure relating to RTOs, ISOs and non-derivative contracts. The following table represents KPCo's exposure if credit ratings were to decline below a specified rating threshold as of June 30, 2016 and December 31, 2015:

	June 30, 2016	December 31, 2015
	(in thousands)	
Amount of Collateral KPCo Would Have Been Required to Post Attributable to RTOs and ISOs	$ 234	$ 1,003
Amount of Collateral Attributable to Other Contracts	203	23

In addition, a majority of KPCo's non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation that is $50 million or greater. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering contractual netting arrangements as of June 30, 2016 and December 31, 2015:

	June 30, 2016	December 31, 2015
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 403	$ 750
Amount of Cash Collateral Posted	—	—
Additional Settlement Liability if Cross Default Provision is Triggered	396	750

9. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability. The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with established risk management policies as approved by the Finance Committee of AEP's Board of Directors. AEPSC's market risk oversight staff independently monitors risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (Regulated Risk Committee) various reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations and Chief Risk Officer.

For commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are nonbinding in nature but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A portion of the Level 3 instruments have been economically hedged which limits potential earnings volatility.

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of KPCo's Long-term Debt as of June 30, 2016 and December 31, 2015 are summarized in the following table:

	June 30, 2016		December 31, 2015	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 866,809	$ 1,006,537	$ 866,451	$ 963,639

Fair Value Measurements of Financial Assets and Liabilities

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 June 30, 2016 and December 31, 2015. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2016

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets – Nonaffiliated and Affiliated					
Risk Management Commodity Contracts (a) (b)	$ 11	$ 3,381	$ 969	$ (3,269)	$ 1,092
Liabilities:					
Risk Management Liabilities – Nonaffiliated					
Risk Management Commodity Contracts (a) (b)	$ 25	$ 3,635	$ 685	$ (3,402)	$ 943

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2015

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets – Nonaffiliated and Affiliated					
Risk Management Commodity Contracts (a) (b)	$ 36	$ 2,692	$ 2,338	$ (2,012)	$ 3,054
Liabilities:					
Risk Management Liabilities – Nonaffiliated					
Risk Management Commodity Contracts (a) (b)	$ 43	$ 3,545	$ 92	$ (2,667)	$ 1,013

(a) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(b) Substantially comprised of power contracts.

There were no transfers between Level 1 and Level 2 during the three and six months ended June 30, 2016 and 2015.

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 June 30, 2016	Net Risk Management Assets (Liabilities) (a)
	(in thousands)
Balance as of March 31, 2016	$ 1,370
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	843
Purchases, Issuances and Settlements (d)	(1,315)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(614)
Balance as of June 30, 2016	$ 284

Three Months Ended June 30, 2015	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of March 31, 2015	$ 1,670
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	(221)
Purchases, Issuances and Settlements (d)	(697)
Transfers out of Level 3 (e) (f)	240
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	4,782
Balance as of June 30, 2015	$ 5,774

Six Months Ended June 30, 2016	Net Risk Management Assets (Liabilities) (a)
	(in thousands)
Balance as of December 31, 2015	$ 2,246
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	1,278
Purchases, Issuances and Settlements (d)	(3,056)
Transfers out of Level 3 (e) (f)	22
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(206)
Balance as of June 30, 2016	$ 284

Six Months Ended June 30, 2015	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of December 31, 2014	$ 3,927
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	365
Purchases, Issuances and Settlements (d)	(3,489)
Transfers out of Level 3 (e) (f)	240
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	4,731
Balance as of June 30, 2015	$ 5,774

(a) Includes both affiliated and nonaffiliated transactions.
(b) Included in revenues on KPCo’s statements of income.
(c) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(d) Represents the settlement of risk management commodity contracts for the reporting period.
(e) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(f) Represents existing assets or liabilities that were previously categorized as Level 3.
(g) Relates to the net gains (losses) of those contracts that are not reflected on KPCo’s statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions as of June 30, 2016 and December 31, 2015:

Significant Unobservable Inputs
June 30, 2016

	Fair Value		Valuation	Significant Unobservable	Forward Price Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$ 615	$ 73	Discounted Cash Flow	Forward Market Price	$ 10.20	$ 50.27	$ 35.25
FTRs	354	612	Discounted Cash Flow	Forward Market Price	0.11	7.63	0.86
Total	$ 969	$ 685					

Significant Unobservable Inputs
December 31, 2015

	Fair Value		Valuation	Significant Unobservable	Forward Price Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$ 1,580	$ 37	Discounted Cash Flow	Forward Market Price	$ 12.61	$ 47.24	$ 32.38
FTRs	758	55	Discounted Cash Flow	Forward Market Price	(6.96)	8.43	1.34
Total	$ 2,338	$ 92					

(a) Represents market prices in dollars per MWh.

The following table provides sensitivity of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts and FTRs as of June 30, 2016 and December 31, 2015:

Sensitivity of Fair Value Measurements

Significant Unobservable Input	Position	Change in Input	Impact on Fair Value Measurement
Forward Market Price	Buy	Increase (Decrease)	Higher (Lower)
Forward Market Price	Sell	Increase (Decrease)	Lower (Higher)

10. INCOME TAXES

AEP System Tax Allocation Agreement

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

Federal and State Income Tax Audit Status

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2011. The IRS examination of years 2011, 2012 and 2013 started in April 2014. KPCo and other AEP subsidiaries received a Revenue Agents Report in April 2016, completing the 2011 through 2013 audit cycle indicating an agreed upon audit. However, the audit is awaiting final approval by the Congressional Joint Committee on Taxation. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to materially impact net income.

KPCo and other AEP subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns. KPCo and other AEP subsidiaries are currently under examination in several state and local jurisdictions. However, it is possible that previously filed tax returns have positions that may be challenged by these tax authorities. Management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income. KPCo is no longer subject to state or local income tax examinations by tax authorities for years before 2009.

11. FINANCING ACTIVITIES

Long-term Debt

KPCo did not have any long-term debt issuances or retirements during the first six months of 2016.

Dividend Restrictions

KPCo pays dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of KPCo to transfer funds to Parent in the form of dividends.

Federal Power Act

The Federal Power Act prohibits KPCo from participating "in the making or paying of any dividends of such public utility from any funds properly included in capital account." This restriction does not limit the ability of KPCo to pay dividends out of retained earnings.

Leverage Restrictions

Pursuant to the credit agreement leverage restrictions, KPCo must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%.

Corporate Borrowing Program – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding borrowings from the Utility Money Pool as of June 30, 2016 and December 31, 2015 are included in Advances from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the six months ended June 30, 2016 are described in the following table:

Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Borrowings from the Utility Money Pool as of June 30, 2016	Authorized Short-Term Borrowing Limit
		(in thousands)			
$ 39,102	$ 10,102	$ 15,839	$ 6,391	$ 16,274	$ 225,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool for the six months ended June 30, 2016 and 2015 are summarized in the following table:

Six Months Ended June 30,	Maximum Interest Rate for Funds Borrowed from the Utility Money Pool	Minimum Interest Rate for Funds Borrowed from the Utility Money Pool	Maximum Interest Rate for Funds Loaned to the Utility Money Pool	Minimum Interest Rate 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
2016	0.84%	0.69%	0.76%	0.75%	0.75%	0.76%
2015	0.59%	0.39%	0.54%	0.42%	0.47%	0.51%

Sale of Receivables – AEP Credit

Under a sale of receivables arrangement, KPCo sells, without recourse, certain of its customer accounts receivable and accrued unbilled revenue balances to AEP Credit and is charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for KPCo's receivables. The costs of customer accounts receivable sold are reported in Other Operation expense on KPCo's statements of income. KPCo manages and services its accounts receivable sold.

AEP Credit's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables and expires in June 2018.

KPCo's amounts of accounts receivable and accrued unbilled revenues sold under the sale of receivables agreement were $43 million and $38 million as of June 30, 2016 and December 31, 2015, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold for the three months ended June 30, 2016 and 2015 were $666 thousand and $713 thousand, respectively, and for the six months ended June 30, 2016 and 2015 were $1.4 million and $1.6 million, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit for the three months ended June 30, 2016 and 2015 were $134.6 million and $118 million, respectively, and for the six months ended June 30, 2016 and 2015 were $289.9 million and $273 million, respectively.

12. VARIABLE INTEREST ENTITIES

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether KPCo is the primary beneficiary of a VIE, management considers factors such as equity at risk, the amount of the VIE's variability KPCo absorbs, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE, variable interests held by related parties and other factors. Management believes that significant assumptions and judgments were applied consistently. KPCo is not the primary beneficiary of any VIE and has not provided financial or other support to any VIE that was not previously contractually required.

AEPSC provides certain managerial and professional services to AEP's subsidiaries. Parent is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. KPCo's total billings from AEPSC for the three months ended June 30, 2016 and 2015 were $13.8 million and $15.6 million, respectively, and for the six months ended June 30, 2016 and 2015 were $29.8 million and $28.8 million, respectively. The carrying amount of liabilities associated with AEPSC as of June 30, 2016 and December 31, 2015 was $4.8 million and $7.7 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of Parent, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant, Unit 1 and leases a 50% interest in Rockport Plant, Unit 2. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP has agreed to provide AEGCo with the funds necessary to satisfy all of the debt obligations of AEGCo. KPCo is considered to have a significant interest in AEGCo due to these transactions. KPCo is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. Due to AEP management's control over AEGCo, KPCo is not considered the primary beneficiary of AEGCo. In the event AEGCo would require financing or other support outside the billings to KPCo, this financing would be provided by AEP. Total billings from AEGCo for the three months ended June 30, 2016 and 2015 were $24 million and $25.7 million, respectively, and for the six months ended June 30, 2016 and 2015 were $43.5 million and $49.3 million, respectively. The carrying amount of liabilities associated with AEGCo as of June 30, 2016 and December 31, 2015 was $8.6 million and $7.7 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

Kentucky Power Company

2016 Third Quarter Report

Financial Statements

AEP AMERICAN ELECTRIC POWER®

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GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AOCI	Accumulated Other Comprehensive Income.
ASU	Accounting Standards Update.
ESP	Electric Security Plans, a PUCO requirement for electric utilities to adjust their rates by filing with the PUCO.
FASB	Financial Accounting Standards Board.
FERC	Federal Energy Regulatory Commission.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PUCO	Public Utilities Commission of Ohio.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SSO	Standard service offer.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2016 and 2015
(in thousands)
(Unaudited)

	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
REVENUES				
Electric Generation, Transmission and Distribution	$ 166,654	$ 154,019	$ 475,267	$ 502,422
Sales to AEP Affiliates	1,636	4,962	6,457	8,896
Other Revenues	249	212	686	600
TOTAL REVENUES	168,539	159,193	482,410	511,918
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	32,722	41,055	85,367	147,840
Purchased Electricity for Resale	8,224	4,167	33,185	22,128
Purchased Electricity from AEP Affiliates	27,653	28,835	71,116	78,103
Other Operation	23,838	21,587	66,681	61,667
Maintenance	18,259	17,788	52,703	54,973
Depreciation and Amortization	21,689	18,915	63,030	67,164
Taxes Other Than Income Taxes	4,741	5,933	15,766	16,932
TOTAL EXPENSES	137,126	138,280	387,848	448,807
OPERATING INCOME	31,413	20,913	94,562	63,111
Other Income (Expense):				
Other Income (Expense)	(578)	1,864	476	2,430
Interest Expense	(11,808)	(11,050)	(34,108)	(33,270)
INCOME BEFORE INCOME TAX EXPENSE	19,027	11,727	60,930	32,271
Income Tax Expense	7,542	4,731	20,755	11,969
NET INCOME	$ 11,485	$ 6,996	$ 40,175	$ 20,302

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

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2016 and 2015
(in thousands)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Net Income	$ 11,485	$ 6,996	$ 40,175	$ 20,302
OTHER COMPREHENSIVE INCOME, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $8 and $8 for the Three Months Ended September 30, 2016 and 2015, Respectively, and $24 and $24 for the Nine Months Ended September 30, 2016 and 2015, Respectively	15	15	45	45
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $2 and $9 for the Three Months Ended September 30, 2016 and 2015, Respectively, and $7 and $27 for the Nine Months Ended September 30, 2016 and 2015, Respectively	4	17	13	50
TOTAL OTHER COMPREHENSIVE INCOME	19	32	58	95
TOTAL COMPREHENSIVE INCOME	$ 11,504	$ 7,028	$ 40,233	$ 20,397

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2016 and 2015
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2014	$ 50,450	$ 517,460	$ 103,069	$ (7,336)	$ 663,643
Common Stock Dividends			(33,000)		(33,000)
Net Income			20,302		20,302
Other Comprehensive Income				95	95
Pension and OPEB Adjustment Related to Mitchell Plant				5,174	5,174
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2015	$ 50,450	$ 517,460	$ 90,371	$ (2,067)	$ 656,214
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2015	$ 50,450	$ 527,309	$ 86,960	$ (1,645)	$ 663,074
Common Stock Dividends			(33,000)		(33,000)
Net Income			40,175		40,175
Other Comprehensive Income				58	58
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2016	$ 50,450	$ 527,309	$ 94,135	$ (1,587)	$ 670,307

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
September 30, 2016 and December 31, 2015
(in thousands)
(Unaudited)

	September 30, 2016	December 31, 2015
CURRENT ASSETS		
Cash and Cash Equivalents	$ 913	$ 867
Accounts Receivable:		
Customers	7,927	13,747
Affiliated Companies	23,418	20,373
Accrued Unbilled Revenues	647	53
Miscellaneous	2,038	110
Allowance for Uncollectible Accounts	(71)	(243)
Total Accounts Receivable	33,959	34,040
Fuel	22,887	22,085
Materials and Supplies	16,649	26,705
Risk Management Assets – Nonaffiliated	640	2,869
Risk Management Assets – Affiliated	—	173
Accrued Tax Benefits	12,239	47,812
Prepayments and Other Current Assets	8,423	4,623
TOTAL CURRENT ASSETS	95,710	139,174
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,180,451	1,118,837
Transmission	574,926	568,963
Distribution	776,462	756,631
Other Property, Plant and Equipment	64,008	58,294
Construction Work in Progress	19,168	59,351
Total Property, Plant and Equipment	2,615,015	2,562,076
Accumulated Depreciation and Amortization	871,460	847,675
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,743,555	1,714,401
OTHER NONCURRENT ASSETS		
Regulatory Assets	564,433	557,956
Long-term Risk Management Assets – Nonaffiliated	35	12
Employee Benefits and Pension Assets	8,061	6,939
Deferred Charges and Other Noncurrent Assets	15,231	17,774
TOTAL OTHER NONCURRENT ASSETS	587,760	582,681
TOTAL ASSETS	$ 2,427,025	$ 2,436,256

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2016 and December 31, 2015
(Unaudited)

	September 30, 2016	December 31, 2015
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 11,384	$ 18,692
Accounts Payable:		
General	36,678	36,882
Affiliated Companies	24,179	25,139
Long-term Debt Due Within One Year – Nonaffiliated	390,000	65,000
Risk Management Liabilities – Nonaffiliated	1,160	1,002
Customer Deposits	26,778	26,916
Accrued Taxes	14,414	26,867
Accrued Interest	6,444	7,928
Other Current Liabilities	38,321	51,110
TOTAL CURRENT LIABILITIES	549,358	259,536
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	476,982	801,451
Long-term Risk Management Liabilities – Nonaffiliated	61	11
Deferred Income Taxes	662,557	636,158
Asset Retirement Obligations	51,890	55,151
Employee Benefits and Pension Obligations	10,746	13,536
Deferred Credits and Other Noncurrent Liabilities	5,124	7,339
TOTAL NONCURRENT LIABILITIES	1,207,360	1,513,646
TOTAL LIABILITIES	1,756,718	1,773,182
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	527,309	527,309
Retained Earnings	94,135	86,960
Accumulated Other Comprehensive Income (Loss)	(1,587)	(1,645)
TOTAL COMMON SHAREHOLDER'S EQUITY	670,307	663,074
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 2,427,025	$ 2,436,256

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2016 and 2015
(in thousands)
(Unaudited)

	Nine Months Ended September 30, 2016	2015
OPERATING ACTIVITIES		
Net Income	$ 40,175	$ 20,302
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	63,030	67,164
Deferred Income Taxes	22,592	44,673
Allowance for Equity Funds Used During Construction	(743)	(739)
Mark-to-Market of Risk Management Contracts	2,588	846
Pension Contributions to Qualified Plan Trust	(1,509)	(1,900)
Property Taxes	11,863	10,663
Deferred Fuel Over/Under-Recovery, Net	(5,825)	(1,076)
Provision for Refund	—	(22,094)
Change in Other Noncurrent Assets	(25,438)	(18,009)
Change in Other Noncurrent Liabilities	(3,966)	2,100
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	81	12,325
Fuel, Materials and Supplies	680	31,959
Accounts Payable	5,513	5,357
Accrued Taxes, Net	23,118	(11,368)
Other Current Assets	(356)	331
Other Current Liabilities	(11,269)	(10,109)
Net Cash Flows from Operating Activities	120,534	130,425
INVESTING ACTIVITIES		
Construction Expenditures	(80,687)	(84,943)
Other Investing Activities	1,078	1,496
Net Cash Flows Used for Investing Activities	(79,609)	(83,447)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	—	24,546
Change in Advances from Affiliates, Net	(7,308)	(38,043)
Principal Payments for Capital Lease Obligations	(736)	(813)
Dividends Paid on Common Stock	(33,000)	(33,000)
Other Financing Activities	165	78
Net Cash Flows Used for Financing Activities	(40,879)	(47,232)
Net Increase (Decrease) in Cash and Cash Equivalents	46	(254)
Cash and Cash Equivalents at Beginning of Period	867	795
Cash and Cash Equivalents at End of Period	$ 913	$ 541
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 34,905	$ 34,168
Net Cash Paid (Received) for Income Taxes	(35,715)	(24,547)
Noncash Acquisitions Under Capital Leases	571	171
Construction Expenditures Included in Current Liabilities as of September 30,	5,963	9,210

See Condensed Notes to Condensed Financial Statements beginning on page 8.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING MATTERS

General

The 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. Net income for the three and nine months ended September 30, 2016 is not necessarily indicative of results that may be expected for the year ending December 31, 2016. The condensed financial statements are unaudited and should be read in conjunction with the audited 2015 financial statements and notes thereto, which are included in KPCo's 2015 Annual Report.

Investment Tax Credits

Investment tax credits (ITC) were historically accounted for under the flow-through method, except where regulatory commissions reflected ITC in the rate-making process. In the third quarter of 2016, KPCo and other AEP subsidiaries changed accounting for the recognition of ITC and elected to apply the preferred deferral methodology. Retrospective application is not necessary for reporting periods prior to 2016 as the financial impact to KPCo was immaterial.

Deferred ITC is amortized to income tax expense over the life of the asset. Amortization of deferred ITC begins when the asset is placed into service, except where regulatory commissions reflect ITC in the rate-making process, then amortization begins when the cash tax benefit is recognized.

Subsequent Events

Management reviewed subsequent events through November 1, 2016, the date that the third quarter 2016 report was issued.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management reviews the new accounting literature to determine its relevance, if any, to KPCo's business. The following final pronouncements will impact the financial statements.

ASU 2014-09 "Revenue from Contracts with Customers" (ASU 2014-09)

In May 2014, the FASB issued ASU 2014-09 clarifying the method used to determine the timing and requirements for revenue recognition on the statements of income. Under the new standard, an entity must identify the performance obligations in a contract, determine the transaction price and allocate the price to specific performance obligations to recognize the revenue when the obligation is completed. The amendments in this update also require disclosure of sufficient information to allow users to understand the nature, amount, timing and uncertainty of revenue and cash flow arising from contracts.

The FASB deferred implementation of ASU 2014-09 under the terms in ASU 2015-14, "Revenue from Contracts with Customers (Topic: 606): Deferral of the Effective Date." The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017. Early adoption is permitted for annual periods beginning after December 15, 2016. As applicable, this standard may change the amount of revenue recognized on the statements of income in each reporting period. Management is analyzing the impact of this new standard and the related ASUs that clarify guidance in the standard. At this time, management cannot estimate the impact of adoption on revenue or net income. Management plans to adopt ASU 2014-09 effective January 1, 2018.

ASU 2015-11 "Simplifying the Measurement of Inventory" (ASU 2015-11)

In July 2015, the FASB issued ASU 2015-11 simplifying the guidance on the subsequent measurement of inventory, excluding inventory measured using last-in, first-out or the retail inventory method. Under the new standard, inventory should be at the lower of cost and net realizable value. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016 with early adoption permitted. Management does not expect the new standard to impact KPCo's results of operations, financial position or cash flows. Management plans to adopt ASU 2015-11 prospectively, effective January 1, 2017.

ASU 2016-01 "Recognition and Measurement of Financial Assets and Financial Liabilities" (ASU 2016-01)

In January 2016, the FASB issued ASU 2016-01 enhancing the reporting model for financial instruments. Under the new standard, equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) are required to be measured at fair value with changes in fair value recognized in net income. The new standard also amends disclosure requirements and requires separate presentation of financial assets and liabilities by measurement category and form of financial asset (that is, securities or loans and receivables) on the balance sheet or the accompanying notes to the financial statements. The amendments also clarify that an entity should evaluate the need for a valuation allowance on a deferred tax asset related to available-for-sale securities in combination with the entity's other deferred tax assets.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017 with early adoption permitted. The amendments will be applied by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. Management plans to adopt ASU 2016-01 effective January 1, 2018.

ASU 2016-02 "Accounting for Leases" (ASU 2016-02)

In February 2016, the FASB issued ASU 2016-02 increasing the transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. Under the new standard, an entity must recognize an asset and liability for operating leases on the balance sheets. Additionally, a capital lease will be known as a finance lease going forward. Leases with lease terms of 12 months or longer will be subject to the new requirements. Fundamentally, the criteria used to determine lease classification will remain the same, but will be more subjective under the new standard.

The new accounting guidance is effective for annual periods beginning after December 15, 2018 with early adoption permitted. The guidance will be applied by means of a modified retrospective approach. The modified retrospective approach will require lessees and lessors to recognize and measure leases at the beginning of the earliest period presented as well as a number of optional practical expedients that entities may elect to apply. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption. Management expects the new standard to impact KPCo's financial position, but not KPCo's results of operations or cash flows. Management plans to adopt ASU 2016-02 effective January 1, 2019.

ASU 2016-09 "Compensation – Stock Compensation" (ASU 2016-09)

In March 2016, the FASB issued ASU 2016-09 simplifying the accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities and classification on the statements of cash flows. Under the new standard, all excess tax benefits and tax deficiencies (including tax benefits of dividends on share-based payment awards) should be recognized as income tax expense or benefit on the statements of income. Under current GAAP, excess tax benefits are recognized in additional paid-in capital while tax deficiencies are recognized either as an offset to accumulated excess tax benefits, if any, or on the statements of income.

The new accounting guidance is effective for annual periods beginning after December 15, 2016. Early adoption is permitted in any interim or annual period. Certain provisions require retrospective/modified retrospective transition while others are to be applied prospectively. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption. Management plans to adopt ASU 2016-09 effective January 1, 2017.

ASU 2016-13 "Measurement of Credit Losses on Financial Instruments" (ASU 2016-13)

In June 2016, the FASB issued ASU 2016-13 requiring an allowance to be recorded for all expected credit losses for financial assets. The allowance for credit losses is based on historical information, current conditions and reasonable and supportable forecasts. The new standard also makes revisions to the other than temporary impairment model for available-for-sale debt securities. Disclosures of credit quality indicators in relation to the amortized cost of financing receivables are further disaggregated by year of origination.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2019 with early adoption permitted for interim and annual periods beginning after December 15, 2018. The amendments will be applied through a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. Management plans to adopt ASU 2016-13 effective January 1, 2020.

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI and details of reclassifications from AOCI for the three and nine months ended September 30, 2016 and 2015. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 6 for additional details.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2016

	Cash Flow Hedges		
	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)		
Balance in AOCI as of June 30, 2016	$ (71)	$ (1,535)	$ (1,606)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	24	—	24
Amortization of Prior Service Cost (Credit)	—	(55)	(55)
Amortization of Actuarial (Gains)/Losses	—	62	62
Reclassifications from AOCI, before Income Tax (Expense) Credit	24	7	31
Income Tax (Expense) Credit	9	3	12
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	15	4	19
Net Current Period Other Comprehensive Income	15	4	19
Balance in AOCI as of September 30, 2016	$ (56)	$ (1,531)	$ (1,587)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2015

	Cash Flow Hedges		
	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)		
Balance in AOCI as of June 30, 2015	$ (131)	$ (1,968)	$ (2,099)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	23	—	23
Amortization of Prior Service Cost (Credit)	—	(10)	(10)
Amortization of Actuarial (Gains)/Losses	—	35	35
Reclassifications from AOCI, before Income Tax (Expense) Credit	23	25	48
Income Tax (Expense) Credit	8	8	16
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	15	17	32
Net Current Period Other Comprehensive Income	15	17	32
Balance in AOCI as of September 30, 2015	$ (116)	$ (1,951)	$ (2,067)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2016

	Cash Flow Hedges		
	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)		
Balance in AOCI as of December 31, 2015	$ (101)	$ (1,544)	$ (1,645)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	70	—	70
Amortization of Prior Service Cost (Credit)	—	(166)	(166)
Amortization of Actuarial (Gains)/Losses	—	186	186
Reclassifications from AOCI, before Income Tax (Expense) Credit	70	20	90
Income Tax (Expense) Credit	25	7	32
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	45	13	58
Net Current Period Other Comprehensive Income	45	13	58
Balance in AOCI as of September 30, 2016	$ (56)	$ (1,531)	$ (1,587)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2015

	Cash Flow Hedges		
	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)		
Balance in AOCI as of December 31, 2014	$ (161)	$ (7,175)	$ (7,336)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	69	—	69
Amortization of Prior Service Cost (Credit)	—	(30)	(30)
Amortization of Actuarial (Gains)/Losses	—	106	106
Reclassifications from AOCI, before Income Tax (Expense) Credit	69	76	145
Income Tax (Expense) Credit	24	26	50
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	45	50	95
Net Current Period Other Comprehensive Income	45	50	95
Pension and OPEB Adjustment Related to Mitchell Plant	—	5,174	5,174
Balance in AOCI as of September 30, 2015	$ (116)	$ (1,951)	$ (2,067)

4. RATE MATTERS

As discussed in KPCo's 2015 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo's 2015 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 2016 and updates KPCo's 2015 Annual Report.

Regulatory Assets Pending Final Regulatory Approval

Noncurrent Regulatory Assets	September 30, 2016	December 31, 2015
	(in thousands)	
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	$ 4,759	$ 4,377
Other Regulatory Assets Pending Final Regulatory Approval	36	—
Total Regulatory Assets Pending Final Regulatory Approval	$ 4,795	$ 4,377

If these costs are ultimately determined not to be recoverable, it could reduce future net income and cash flows and impact financial condition.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, KPCo's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against KPCo cannot be predicted. Management accrues contingent liabilities only when management concludes that it is both probable that a liability has been incurred at the date of the financial statements and the amount of loss can be reasonably estimated. When management determines that it is not probable, but rather reasonably possible that a liability has been incurred at the date of the financial statements, management discloses such contingencies and the possible loss or range of loss if such estimate can be made. Any estimated range is based on currently available information and involves elements of judgment and significant uncertainties. Any estimated range of possible loss may not represent the maximum possible loss exposure. Circumstances change over time and actual results may vary significantly from estimates.

For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements. The Commitments, Guarantees and Contingencies note within KPCo's 2015 Annual Report should be read in conjunction with this report.

GUARANTEES

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

Letter of Credit

KPCo has $65 million of variable rate Pollution Control Bonds supported by a bilateral letter of credit for $65.7 million. The letter of credit matures in June 2017.

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of September 30, 2016, there were no material liabilities recorded for any indemnifications.

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

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, KPCo is committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance. As of September 30, 2016, the maximum potential loss for these lease agreements was $1.6 million assuming the fair value of the equipment is zero at the end of the lease term.

6. BENEFIT PLANS

KPCo participates in an AEP sponsored qualified pension plan and an unfunded nonqualified pension plan. Substantially all of KPCo's employees are covered by the qualified plan or both the qualified and nonqualified pension plans. KPCo also participates in OPEB plans sponsored by AEP to provide health and life insurance benefits for retired employees.

Components of Net Periodic Benefit Cost

The following tables provide the components of KPCo's net periodic benefit cost (credit) for the plans for the three and nine months ended September 30, 2016 and 2015:

	Pension Plans		**Other Postretirement Benefit Plans**	
	Three Months Ended September 30,		**Three Months Ended September 30,**	
	2016	**2015**	**2016**	**2015**
	(in thousands)			
Service Cost	$ 615	$ 670	$ 71	$ 86
Interest Cost	1,872	1,832	538	488
Expected Return on Plan Assets	(2,533)	(2,495)	(989)	(1,015)
Amortization of Prior Service Cost (Credit)	13	13	(606)	(606)
Amortization of Net Actuarial Loss	736	945	288	155
Net Periodic Benefit Cost (Credit)	$ 703	$ 965	$ (698)	$ (892)

	Pension Plans		**Other Postretirement Benefit Plans**	
	Nine Months Ended September 30,		**Nine Months Ended September 30,**	
	2016	**2015**	**2016**	**2015**
	(in thousands)			
Service Cost	$ 1,845	$ 2,010	$ 212	$ 258
Interest Cost	5,617	5,495	1,613	1,464
Expected Return on Plan Assets	(7,599)	(7,486)	(2,966)	(3,045)
Amortization of Prior Service Cost (Credit)	39	39	(1,818)	(1,818)
Amortization of Net Actuarial Loss	2,207	2,838	863	466
Net Periodic Benefit Cost (Credit)	$ 2,109	$ 2,896	$ (2,096)	$ (2,675)

7. BUSINESS SEGMENTS

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

8. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of KPCo.

KPCo is exposed to certain market risks as a major power producer and participant in the electricity, natural gas, coal and emission allowance markets. 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. Management utilizes derivative instruments to manage these risks.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

The strategy surrounding the use of derivative instruments primarily focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. The risk management strategies also include the use of derivative instruments for trading purposes which focus on seizing market opportunities to create value driven by expected changes in the market prices of the commodities. To accomplish these objectives, KPCo primarily employs risk management contracts including physical and financial forward purchase-and-sale contracts and, to a lesser extent, OTC swaps and options. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

KPCo utilizes power, capacity, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. KPCo utilizes interest rate derivative contracts in order to manage the interest rate exposure associated with its commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. KPCo also utilizes derivative contracts to manage 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 the Board of Directors.

The following table represents the gross notional volume of KPCo's outstanding derivative contracts as of September 30, 2016 and December 31, 2015:

Notional Volume of Derivative Instruments

	Volume		
Primary Risk Exposure	**September 30, 2016**	**December 31, 2015**	**Unit of Measure**
	(in thousands)		
Commodity:			
Power	13,026	7,864	MWhs
Natural Gas	8	64	MMBtus
Heating Oil and Gasoline	317	341	Gallons
Interest Rate	$ 22	$ 500	USD

Cash Flow Hedging Strategies

KPCo utilizes cash flow hedges on certain derivative transactions for the purchase and sale of power ("Commodity") in order to manage the variable price risk related to forecasted purchases and sales. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and purchases. KPCo does not hedge all commodity price risk.

KPCo utilizes a variety of interest rate derivative transactions in order to manage interest rate risk exposure. KPCo also utilizes interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. KPCo does not hedge all interest rate exposure.

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

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities on the balance sheets 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 risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the September 30, 2016 and December 31, 2015 balance sheets, KPCo netted $18 thousand and $0, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $30 thousand and $656 thousand, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following tables represent the gross fair value of KPCo's derivative activity on the balance sheets as of September 30, 2016 and December 31, 2015:

Fair Value of Derivative Instruments
September 30, 2016

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in thousands)	
Current Risk Management Assets - Nonaffiliated	$ 2,340	$ (1,700)	$ 640
Long-term Risk Management Assets - Nonaffiliated	179	(144)	35
Total Assets	2,519	(1,844)	675
Current Risk Management Liabilities - Nonaffiliated	2,872	(1,712)	1,160
Long-term Risk Management Liabilities - Nonaffiliated	205	(144)	61
Total Liabilities	3,077	(1,856)	1,221
Total MTM Derivative Contract Net Assets (Liabilities)	$ (558)	$ 12	$ (546)

Fair Value of Derivative Instruments
December 31, 2015

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in thousands)	
Current Risk Management Assets - Nonaffiliated and Affiliated	$ 5,017	$ (1,975)	$ 3,042
Long-term Risk Management Assets - Nonaffiliated	59	(47)	12
Total Assets	5,076	(2,022)	3,054
Current Risk Management Liabilities - Nonaffiliated	3,621	(2,619)	1,002
Long-term Risk Management Liabilities - Nonaffiliated	69	(58)	11
Total Liabilities	3,690	(2,677)	1,013
Total MTM Derivative Contract Net Assets	$ 1,386	$ 655	$ 2,041

(a) Derivative instruments within this category are reported gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."
(c) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

The table below presents KPCo's activity of derivative risk management contracts for the three and nine months ended September 30, 2016 and 2015:

Amount of Gain (Loss) Recognized on Risk Management Contracts For the Three and Nine Months Ended September 30, 2016 and 2015

Location of Gain (Loss)	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
	(in thousands)			
Electric Generation, Transmission and Distribution Revenues	$ 243	$ 77	$ 191	$ 2,234
Sales to AEP Affiliates	5	728	434	977
Fuel and Other Consumables Used for Electric Generation	—	(7)	—	(20)
Purchased Electricity for Resale	463	758	1,902	3,331
Other Operation Expense	(9)	(23)	(42)	(75)
Maintenance Expense	(21)	(40)	(78)	(111)
Regulatory Assets (a)	(551)	624	(406)	944
Regulatory Liabilities (a)	681	(919)	237	(962)
Total Gain on Risk Management Contracts	$ 811	$ 1,198	$ 2,238	$ 6,318

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

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

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

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on KPCo's statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on KPCo's statements of income depending on the relevant facts and circumstances. Certain derivatives that economically hedge future commodity risk are recorded in the same expense line item on the statements of income as that of the associated risk. However, unrealized and some realized gains and losses for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains), in accordance with the accounting guidance for "Regulated Operations."

In connection with OPCo's June 2012 - May 2015 ESP, the PUCO ordered OPCo to conduct energy and capacity auctions for its entire SSO load for delivery beginning in June 2015. These auctions resulted in a range of products, including 12-month, 24-month, and 36-month periods. The delivery period for each contract is scheduled to start on the first day of June of each year, immediately following the auction. Certain affiliated entities, including KPCo, participated in the auction process and were awarded tranches of OPCo's SSO load. The underlying contracts are derivatives subject to the accounting guidance for "Derivatives and Hedging" and are accounted for using MTM accounting, unless the contract has been designated as a normal purchase or normal sale.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), KPCo initially reports the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the balance sheets until the period the hedged item affects Net Income. KPCo would recognize any hedge ineffectiveness as a regulatory asset (for losses) or a regulatory liability (for gains) if applicable.

Realized gains and losses on derivative contracts for the purchase and sale of power designated as cash flow hedges are included in Total Revenues or Purchased Electricity for Resale on KPCo's statements of income, or in Regulatory Assets or Regulatory Liabilities on KPCo's balance sheets, depending on the specific nature of the risk being hedged. During the three and nine months ended September 30, 2016 and 2015, KPCo did not designate power derivatives as cash flow hedges.

KPCo reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on its balance sheets into Interest Expense on its statements of income in those periods in which hedged interest payments occur. During the three and nine months ended September 30, 2016 and 2015, KPCo did not apply cash flow hedging to outstanding interest rate derivatives.

During the three and nine months ended September 30, 2016 and 2015, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

For details on effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's balance sheets and the reasons for changes in cash flow hedges, see Note 3.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's balance sheets as of September 30, 2016 and December 31, 2015 were:

Impact of Cash Flow Hedges on the Condensed Balance Sheet

	Interest Rate	
	September 30, 2016	**December 31, 2015**
	(in thousands)	
AOCI Loss Net of Tax	$ (56)	$ (101)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(55)	(60)

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 September 30, 2016, KPCo is not hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") its exposure to variability in future cash flows related to forecasted transactions.

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

Master agreements are typically used to facilitate the netting of cash flows associated with a single counterparty and may include collateral requirements. Collateral requirements in the form of cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. A counterparty is required 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, master agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, KPCo is obligated to post an additional amount of collateral if certain credit ratings decline below a specified rating threshold. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. KPCo has not experienced a downgrade below a specified rating threshold that would require the posting of additional collateral. There is no exposure relating to derivative contracts, however, there is exposure relating to RTOs, ISOs and non-derivative contracts. The following table represents KPCo's exposure if credit ratings were to decline below a specified rating threshold as of September 30, 2016 and December 31, 2015:

	September 30, 2016	December 31, 2015
	(in thousands)	
Amount of Collateral KPCo Would Have Been Required to Post Attributable to RTOs and ISOs	$ 859	$ 1,003
Amount of Collateral Attributable to Other Contracts	1,641	23

In addition, a majority of KPCo's non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation that is $50 million or greater. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering contractual netting arrangements as of September 30, 2016 and December 31, 2015:

	September 30, 2016	December 31, 2015
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 261	$ 750
Amount of Cash Collateral Posted	—	—
Additional Settlement Liability if Cross Default Provision is Triggered	255	750

9. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability. The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with established risk management policies as approved by the Finance Committee of AEP's Board of Directors. AEPSC's market risk oversight staff independently monitors risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (Regulated Risk Committee) various reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations and Chief Risk Officer.

For commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are nonbinding in nature but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A portion of the Level 3 instruments have been economically hedged which limits potential earnings volatility.

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of KPCo's Long-term Debt as of September 30, 2016 and December 31, 2015 are summarized in the following table:

	September 30, 2016		December 31, 2015	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 866,982	$ 1,002,085	$ 866,451	$ 963,639

Fair Value Measurements of Financial Assets and Liabilities

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 September 30, 2016 and December 31, 2015. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2016

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets – Nonaffiliated					
Risk Management Commodity Contracts (a) (b)	$ 5	$ 1,609	$ 733	$ (1,672)	$ 675
Liabilities:					
Risk Management Liabilities – Nonaffiliated					
Risk Management Commodity Contracts (a) (b)	$ 5	$ 1,729	$ 1,171	$ (1,684)	$ 1,221

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2015

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets – Nonaffiliated and Affiliated					
Risk Management Commodity Contracts (a) (b)	$ 36	$ 2,692	$ 2,338	$ (2,012)	$ 3,054
Liabilities:					
Risk Management Liabilities – Nonaffiliated					
Risk Management Commodity Contracts (a) (b)	$ 43	$ 3,545	$ 92	$ (2,667)	$ 1,013

(a) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(b) Substantially comprised of power contracts.

There were no transfers between Level 1 and Level 2 during the three and nine months ended September 30, 2016 and 2015.

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 September 30, 2016	**Net Risk Management Assets (Liabilities) (a)**
	(in thousands)
Balance as of June 30, 2016	$ 284
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	844
Purchases, Issuances and Settlements (d)	(1,006)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(560)
Balance as of September 30, 2016	$ (438)

Three Months Ended September 30, 2015	**Net Risk Management Assets (Liabilities) (a)**
	(in thousands)
Balance as of June 30, 2015	$ 5,774
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	34
Purchases, Issuances and Settlements (d)	(2,031)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(330)
Balance as of September 30, 2015	$ 3,447

Nine Months Ended September 30, 2016	**Net Risk Management Assets (Liabilities) (a)**
	(in thousands)
Balance as of December 31, 2015	$ 2,246
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	1,360
Purchases, Issuances and Settlements (d)	(3,393)
Transfers out of Level 3 (e) (f)	22
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(673)
Balance as of September 30, 2016	$ (438)

Nine Months Ended September 30, 2015	**Net Risk Management Assets (Liabilities) (a)**
	(in thousands)
Balance as of December 31, 2014	$ 3,927
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	698
Purchases, Issuances and Settlements (d)	(4,076)
Transfers out of Level 3 (e) (f)	240
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	2,658
Balance as of September 30, 2015	$ 3,447

(a) Includes both affiliated and nonaffiliated transactions.
(b) Included in revenues on KPCo’s statements of income.
(c) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(d) Represents the purchases, issuances and settlements of risk management commodity contracts for the reporting period.
(e) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(f) Represents existing assets or liabilities that were previously categorized as Level 3.
(g) Relates to the net gains (losses) of those contracts that are not reflected on KPCo’s statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions as of September 30, 2016 and December 31, 2015:

Significant Unobservable Inputs
September 30, 2016

	Fair Value		Valuation	Significant	Forward Price Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$ 433	$ 51	Discounted Cash Flow	Forward Market Price	$ 16.51	$ 47.42	$ 34.85
FTRs	300	1,120	Discounted Cash Flow	Forward Market Price	(0.22)	10.63	0.74
Total	$ 733	$ 1,171					

Significant Unobservable Inputs
December 31, 2015

	Fair Value		Valuation	Significant	Forward Price Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$ 1,580	$ 37	Discounted Cash Flow	Forward Market Price	$ 12.61	$ 47.24	$ 32.38
FTRs	758	55	Discounted Cash Flow	Forward Market Price	(6.96)	8.43	1.34
Total	$ 2,338	$ 92					

(a) Represents market prices in dollars per MWh.

The following table provides sensitivity of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts and FTRs as of September 30, 2016 and December 31, 2015:

Sensitivity of Fair Value Measurements

Significant Unobservable Input	Position	Change in Input	Impact on Fair Value Measurement
Forward Market Price	Buy	Increase (Decrease)	Higher (Lower)
Forward Market Price	Sell	Increase (Decrease)	Lower (Higher)

10. INCOME TAXES

AEP System Tax Allocation Agreement

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

Federal and State Income Tax Audit Status

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2011. The IRS examination of years 2011, 2012 and 2013 started in April 2014. KPCo and other AEP subsidiaries received a Revenue Agents Report in April 2016, completing the 2011 through 2013 audit cycle indicating an agreed upon audit. The 2011 through 2013 audit was submitted to the Congressional Joint Committee on Taxation for approval. KPCo and other AEP subsidiaries were informed that the IRS expects the Joint Committee to refer the audit back to the IRS exam team for further consideration. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to materially impact net income.

KPCo and other AEP subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns. KPCo and other AEP subsidiaries are currently under examination in several state and local jurisdictions. However, it is possible that previously filed tax returns have positions that may be challenged by these tax authorities. Management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income. KPCo is no longer subject to state or local income tax examinations by tax authorities for years before 2009.

11. FINANCING ACTIVITIES

Long-term Debt

KPCo did not have any long-term debt issuances or retirements during the first nine months of 2016.

Dividend Restrictions

KPCo pays dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of KPCo to transfer funds to Parent in the form of dividends.

Federal Power Act

The Federal Power Act prohibits KPCo from participating "in the making or paying of any dividends of such public utility from any funds properly included in capital account." This restriction does not limit the ability of KPCo to pay dividends out of retained earnings.

Leverage Restrictions

Pursuant to the credit agreement leverage restrictions, KPCo must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%.

Corporate Borrowing Program – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding borrowings from the Utility Money Pool as of September 30, 2016 and December 31, 2015 are included in Advances from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the nine months ended September 30, 2016 are described in the following table:

Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Borrowings from the Utility Money Pool as of September 30, 2016	Authorized Short-Term Borrowing Limit
		(in thousands)			
$ 39,102	$ 15,557	$ 13,910	$ 7,277	$ 11,384	$ 225,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool are summarized in the following table:

Nine Months Ended September 30,	Maximum Interest Rate for Funds Borrowed from the Utility Money Pool	Minimum Interest Rate for Funds Borrowed from the Utility Money Pool	Maximum Interest Rate for Funds Loaned to the Utility Money Pool	Minimum Interest Rate 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
2016	0.91%	0.69%	0.90%	0.75%	0.77%	0.87%
2015	0.59%	0.39%	0.54%	0.42%	0.46%	0.51%

Sale of Receivables – AEP Credit

Under a sale of receivables arrangement, KPCo sells, without recourse, certain of its customer accounts receivable and accrued unbilled revenue balances to AEP Credit and is charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for KPCo's receivables. The costs of customer accounts receivable sold are reported in Other Operation expense on KPCo's statements of income. KPCo manages and services its accounts receivable sold.

AEP Credit's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables and expires in June 2018.

KPCo's amounts of accounts receivable and accrued unbilled revenues sold under the sale of receivables agreement were $45.2 million and $38 million as of September 30, 2016 and December 31, 2015, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold for the three months ended September 30, 2016 and 2015 were $722 thousand and $814 thousand, respectively, and for the nine months ended September 30, 2016 and 2015 were $2.1 million and $2.4 million, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit for the three months ended September 30, 2016 and 2015 were $149.7 million and $127 million, respectively, and for the nine months ended September 30, 2016 and 2015 were $439.6 million and $400.5 million, respectively.

12. VARIABLE INTEREST ENTITIES

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether KPCo is the primary beneficiary of a VIE, management considers factors such as equity at risk, the amount of the VIE's variability KPCo absorbs, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE, variable interests held by related parties and other factors. Management believes that significant assumptions and judgments were applied consistently. KPCo is not the primary beneficiary of any VIE and has not provided financial or other support to any VIE that was not previously contractually required.

AEPSC provides certain managerial and professional services to AEP's subsidiaries. Parent is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. KPCo's total billings from AEPSC for the three months ended September 30, 2016 and 2015 were $12.3 million and $15 million, respectively, and for the nine months ended September 30, 2016 and 2015 were $42.1 million and $43.8 million, respectively. The carrying amount of liabilities associated with AEPSC as of September 30, 2016 and December 31, 2015 was $4.1 million and $7.7 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of Parent, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant, Unit 1 and leases a 50% interest in Rockport Plant, Unit 2. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP has agreed to provide AEGCo with the funds necessary to satisfy all of the debt obligations of AEGCo. KPCo is considered to have a significant interest in AEGCo due to these transactions. KPCo is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. Due to AEP management's control over AEGCo, KPCo is not considered the primary beneficiary of AEGCo. In the event AEGCo would require financing or other support outside the billings to KPCo, this financing would be provided by AEP. Total billings from AEGCo for the three months ended September 30, 2016 and 2015 were $27.6 million and $28.8 million, respectively, and for the nine months ended September 30, 2016 and 2015 were $71.1 million and $78.1 million, respectively. The carrying amount of liabilities associated with AEGCo as of September 30, 2016 and December 31, 2015 was $7.9 million and $7.7 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

Kentucky Power Company

2017 First Quarter Report

Financial Statements

KENTUCKY POWER
An AEP Company
BOUNDLESS ENERGY

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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	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AOCI	Accumulated Other Comprehensive Income.
ASU	Accounting Standards Update.
FASB	Financial Accounting Standards Board.
FERC	Federal Energy Regulatory Commission.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2017 and 2016
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2017	2016
REVENUES		
Electric Generation, Transmission and Distribution	$ 162,538	$ 164,295
Sales to AEP Affiliates	3,251	3,163
Other Revenues	224	213
TOTAL REVENUES	166,013	167,671
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	23,436	28,840
Purchased Electricity for Resale	14,415	13,815
Purchased Electricity from AEP Affiliates	23,104	19,462
Other Operation	27,753	19,970
Maintenance	20,312	17,677
Depreciation and Amortization	22,095	21,066
Taxes Other Than Income Taxes	5,735	5,810
TOTAL EXPENSES	136,850	126,640
OPERATING INCOME	29,163	41,031
Other Income (Expense):		
Other Income	768	329
Interest Expense	(11,469)	(11,244)
INCOME BEFORE INCOME TAX EXPENSE	18,462	30,116
Income Tax Expense	6,349	10,313
NET INCOME	$ 12,113	$ 19,803

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

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2017 and 2016
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
Net Income	$ 12,113	$ 19,803
OTHER COMPREHENSIVE INCOME, NET OF TAXES		
Cash Flow Hedges, Net of Tax of $9 and $8 in 2017 and 2016, Respectively	16	15
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $4 and $2 in 2017 and 2016, Respectively	8	4
TOTAL OTHER COMPREHENSIVE INCOME	24	19
TOTAL COMPREHENSIVE INCOME	$ 12,137	$ 19,822

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2017 and 2016
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2015	$ 50,450	$ 527,309	$ 86,960	$ (1,645)	$ 663,074
Common Stock Dividends			(11,000)		(11,000)
Net Income			19,803		19,803
Other Comprehensive Income				19	19
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2016	$ 50,450	$ 527,309	$ 95,763	$ (1,626)	$ 671,896
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2016	$ 50,450	$ 526,135	$ 93,170	$ (1,354)	$ 668,401
Common Stock Dividends			(8,750)		(8,750)
Net Income			12,113		12,113
Other Comprehensive Income				24	24
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2017	$ 50,450	$ 526,135	$ 96,533	$ (1,330)	$ 671,788

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
March 31, 2017 and December 31, 2016
(in thousands)
(Unaudited)

	March 31, 2017	December 31, 2016
CURRENT ASSETS		
Cash and Cash Equivalents	$ 814	$ 859
Accounts Receivable:		
Customers	11,785	14,608
Affiliated Companies	22,799	29,519
Accrued Unbilled Revenues	3,948	4,542
Miscellaneous	368	380
Allowance for Uncollectible Accounts	(63)	(66)
Total Accounts Receivable	38,837	48,983
Fuel	19,727	19,823
Materials and Supplies	16,618	16,540
Risk Management Assets	418	457
Accrued Tax Benefits	502	574
Prepayments and Other Current Assets	6,753	8,347
TOTAL CURRENT ASSETS	83,669	95,583
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,184,395	1,182,212
Transmission	575,326	574,703
Distribution	790,373	783,283
Other Property, Plant and Equipment	68,178	67,248
Construction Work in Progress	30,147	27,380
Total Property, Plant and Equipment	2,648,419	2,634,826
Accumulated Depreciation and Amortization	893,661	879,253
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,754,758	1,755,573
OTHER NONCURRENT ASSETS		
Regulatory Assets	563,919	576,131
Long-term Risk Management Assets	28	—
Employee Benefits and Pension Assets	6,229	5,891
Deferred Charges and Other Noncurrent Assets	22,977	26,787
TOTAL OTHER NONCURRENT ASSETS	593,153	608,809
TOTAL ASSETS	$ 2,431,580	$ 2,459,965

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2017 and December 31, 2016
(Unaudited)

	March 31, 2017	December 31, 2016
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 12,172	$ 1,807
Accounts Payable:		
General	29,126	52,601
Affiliated Companies	23,822	28,579
Long-term Debt Due Within One Year – Nonaffiliated	390,000	390,000
Risk Management Liabilities	71	53
Customer Deposits	27,024	26,625
Accrued Taxes	20,082	28,379
Accrued Interest	6,415	8,127
Other Current Liabilities	36,380	44,302
TOTAL CURRENT LIABILITIES	545,092	580,473
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	477,345	477,164
Long-term Risk Management Liabilities	16	313
Deferred Income Taxes	672,589	666,902
Asset Retirement Obligations	45,284	46,657
Employee Benefits and Pension Obligations	13,376	14,516
Deferred Credits and Other Noncurrent Liabilities	6,090	5,539
TOTAL NONCURRENT LIABILITIES	1,214,700	1,211,091
TOTAL LIABILITIES	1,759,792	1,791,564
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	526,135	526,135
Retained Earnings	96,533	93,170
Accumulated Other Comprehensive Income (Loss)	(1,330)	(1,354)
TOTAL COMMON SHAREHOLDER'S EQUITY	671,788	668,401
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 2,431,580	$ 2,459,965

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2017 and 2016
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2017	2016
OPERATING ACTIVITIES		
Net Income	$ 12,113	$ 19,803
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	22,095	21,066
Deferred Income Taxes	5,842	10,561
Allowance for Equity Funds Used During Construction	(213)	(405)
Mark-to-Market of Risk Management Contracts	(268)	733
Property Taxes	3,777	3,822
Deferred Fuel Over/Under-Recovery, Net	(534)	(1,192)
Change in Other Noncurrent Assets	5,495	(10,441)
Change in Other Noncurrent Liabilities	(121)	(416)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	10,146	(9,076)
Fuel, Materials and Supplies	233	104
Accounts Payable	(23,324)	(7,594)
Accrued Taxes, Net	(8,225)	30,201
Accrued Interest	(1,712)	(1,636)
Other Current Assets	2,158	(806)
Other Current Liabilities	(6,652)	(9,111)
Net Cash Flows from Operating Activities	20,810	45,613
INVESTING ACTIVITIES		
Construction Expenditures	(22,412)	(31,687)
Other Investing Activities	173	555
Net Cash Flows Used for Investing Activities	(22,239)	(31,132)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	10,365	(2,902)
Principal Payments for Capital Lease Obligations	(247)	(229)
Dividends Paid on Common Stock	(8,750)	(11,000)
Other Financing Activities	16	154
Net Cash Flows from (Used for) Financing Activities	1,384	(13,977)
Net Increase (Decrease) in Cash and Cash Equivalents	(45)	504
Cash and Cash Equivalents at Beginning of Period	859	867
Cash and Cash Equivalents at End of Period	$ 814	$ 1,371
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 12,938	$ 12,621
Net Cash Paid (Received) for Income Taxes	4	(38,806)
Noncash Acquisitions Under Capital Leases	109	402
Construction Expenditures Included in Current Liabilities as of March 31,	6,069	12,924

See Condensed Notes to Condensed Financial Statements beginning on page 8.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING MATTERS

General

The 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. Net income for the three months ended March 31, 2017 is not necessarily indicative of results that may be expected for the year ending December 31, 2017. The condensed financial statements are unaudited and should be read in conjunction with the audited 2016 financial statements and notes thereto, which are included in KPCo's 2016 Annual Report.

Subsequent Events

Management reviewed subsequent events through April 27, 2017, the date that the first quarter 2017 report was issued.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management reviews the new accounting literature to determine its relevance, if any, to KPCo's business. The following final pronouncements will impact the financial statements.

ASU 2014-09 "Revenue from Contracts with Customers" (ASU 2014-09)

In May 2014, the FASB issued ASU 2014-09 clarifying the method used to determine the timing and requirements for revenue recognition on the statements of income. Under the new standard, an entity must identify the performance obligations in a contract, determine the transaction price and allocate the price to specific performance obligations to recognize the revenue when the obligation is completed. The amendments in this update also require disclosure of sufficient information to allow users to understand the nature, amount, timing and uncertainty of revenue and cash flow arising from contracts.

The FASB deferred implementation of ASU 2014-09 under the terms in ASU 2015-14, "Revenue from Contracts with Customers (Topic: 606): Deferral of the Effective Date." The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017 with early adoption permitted.

Management continues to analyze the impact of the new revenue standard and related ASUs. During 2016 and continuing through the first quarter of 2017, revenue contract assessments were completed. Material revenue streams were identified within the AEP System and representative contract/transaction types were sampled. Performance obligations identified within each material revenue stream were evaluated to determine whether the obligations were satisfied at a point in time or over time. Contracts determined to be satisfied over time generally qualified for the invoicing practical expedient since the invoiced amounts reasonably represented the value to customers of performance obligations fulfilled to date. Based upon the completed assessments, management does not expect a material impact to the timing of revenue recognized or net income and plans to elect the modified retrospective transition approach upon adoption. Management also continues to monitor unresolved industry implementation issues, including items related to collectability, and will analyze the related impacts to revenue recognition. Management plans to adopt ASU 2014-09 effective January 1, 2018.

ASU 2016-01 "Recognition and Measurement of Financial Assets and Financial Liabilities" (ASU 2016-01)

In January 2016, the FASB issued ASU 2016-01 enhancing the reporting model for financial instruments. Under the new standard, equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) are required to be measured at fair value with changes in fair value recognized in net income. The new standard also amends disclosure requirements and requires separate presentation of financial assets and liabilities by measurement category and form of financial asset (that is, securities or loans and receivables) on the balance sheet or the accompanying notes to the financial statements. The amendments also clarify that an entity should evaluate the need for a valuation allowance on a deferred tax asset related to available-for-sale securities in combination with the entity's other deferred tax assets.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017 with early adoption permitted. The amendments will be applied by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. Management plans to adopt ASU 2016-01 effective January 1, 2018.

ASU 2016-02 "Accounting for Leases" (ASU 2016-02)

In February 2016, the FASB issued ASU 2016-02 increasing the transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. Under the new standard, an entity must recognize an asset and liability for operating leases on the balance sheets. Additionally, a capital lease will be known as a finance lease going forward. Leases with lease terms of 12 months or longer will be subject to the new requirements. Fundamentally, the criteria used to determine lease classification will remain the same, but will be more subjective under the new standard.

The new accounting guidance is effective for annual periods beginning after December 15, 2018 with early adoption permitted. The guidance will be applied by means of a modified retrospective approach. The modified retrospective approach will require lessees and lessors to recognize and measure leases at the beginning of the earliest period presented.

Management continues to analyze the impact of the new lease standard. During 2016 and continuing through the first quarter of 2017, lease contract assessments were completed. The AEP System lease population was identified and representative lease contracts were sampled. Based upon the completed assessments, management prepared a system gap analysis to outline new disclosure compliance requirements compared to current system capabilities. Lease system options are currently being evaluated. Management plans to elect certain of the following practical expedients upon adoption:

Practical Expedient	Description
Overall Expedients (for leases commenced prior to adoption date and must be adopted as a package)	Do not need to reassess whether any expired or existing contracts are/or contain leases, do not need to reassess the lease classification for any expired or existing leases and do not need to reassess initial direct costs for any existing leases.
Lease and Non-lease Components (elect by class of underlying asset)	Elect as an accounting policy to not separate non-lease components from lease components and instead account for each lease and associated non-lease component as a single lease component.
Short-term Lease (elect by class of underlying asset)	Elect as an accounting policy to not apply the recognition requirements to short-term leases.
Lease term	Elect to use hindsight to determine the lease term.

Management expects the new standard to impact financial position, but not results of operations or cash flows. Management also continues to monitor unresolved industry implementation issues, including items related to renewables and PPAs, pole attachments, easements and right-of-ways, and will analyze the related impacts to lease accounting. Management plans to adopt ASU 2016-02 effective January 1, 2019.

ASU 2016-09 "Compensation – Stock Compensation" (ASU 2016-09)

In March 2016, the FASB issued ASU 2016-09 simplifying the accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities and classification on the statements of cash flows. Under the new standard, all excess tax benefits and tax deficiencies (including tax benefits of dividends on share-based payment awards) should be recognized as income tax expense or benefit on the statements of income. Under current GAAP, excess tax benefits are recognized in additional paid-in capital while tax deficiencies are recognized either as an offset to accumulated excess tax benefits, if any, or on the statements of income.

Management adopted ASU 2016-09 effective January 1, 2017. As a result of the adoption of this guidance, management made an accounting policy election to recognize the effect of forfeitures in compensation cost when they occur. There was an immaterial impact on results of operations and financial position and no impact on cash flows at adoption.

ASU 2016-13 "Measurement of Credit Losses on Financial Instruments" (ASU 2016-13)

In June 2016, the FASB issued ASU 2016-13 requiring an allowance to be recorded for all expected credit losses for financial assets. The allowance for credit losses is based on historical information, current conditions and reasonable and supportable forecasts. The new standard also makes revisions to the other than temporary impairment model for available-for-sale debt securities. Disclosures of credit quality indicators in relation to the amortized cost of financing receivables are further disaggregated by year of origination.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2019 with early adoption permitted for interim and annual periods beginning after December 15, 2018. The amendments will be applied through a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. Management plans to adopt ASU 2016-13 effective January 1, 2020.

ASU 2016-18 "Restricted Cash" (ASU 2016-18)

In November 2016, the FASB issued ASU 2016-18 clarifying the treatment of restricted cash on the statements of cash flows. Under the new standard, amounts considered restricted cash will be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts on the statements of cash flows.

The new accounting guidance is effective for annual periods beginning after December 15, 2017. Early adoption is permitted in any interim or annual period. The guidance will be applied by means of a retrospective approach. Management is analyzing the impact of the new standard. Management plans to adopt ASU 2016-18 effective for the 2017 Annual Report.

ASU 2017-07 "Compensation - Retirement Benefits" (ASU 2017-07)

In March 2017, the FASB issued ASU 2017-07 requiring that an employer report the service cost component of pension and postretirement benefits in the same line item or items as other compensation costs. The other components of net benefit cost are required to be presented in the income statement separately from the service cost component and outside of a subtotal of income from operations. In addition, only the service cost component will be eligible for capitalization as applicable following labor.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017. Early adoption is permitted as of the beginning of an annual period for which financial statements have not been issued or made available for issuance. Management is analyzing the impact of the new standard. Management plans to adopt ASU 2017-07 effective January 1, 2018.

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI and details of reclassifications from AOCI for the three months ended March 31, 2017 and 2016. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 6 for additional details.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2017

	Cash Flow Hedges		
	Interest Rate	Pension and OPEB	Total
	(in thousands)		
Balance in AOCI as of December 31, 2016	$ (41)	$ (1,313)	$ (1,354)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	23	—	23
Amortization of Prior Service Cost (Credit)	—	(55)	(55)
Amortization of Actuarial (Gains)/Losses	—	67	67
Reclassifications from AOCI, before Income Tax (Expense) Credit	23	12	35
Income Tax (Expense) Credit	7	4	11
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	16	8	24
Net Current Period Other Comprehensive Income	16	8	24
Balance in AOCI as of March 31, 2017	$ (25)	$ (1,305)	$ (1,330)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2016

	Cash Flow Hedges		
	Interest Rate	Pension and OPEB	Total
	(in thousands)		
Balance in AOCI as of December 31, 2015	$ (101)	$ (1,544)	$ (1,645)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	23	—	23
Amortization of Prior Service Cost (Credit)	—	(55)	(55)
Amortization of Actuarial (Gains)/Losses	—	62	62
Reclassifications from AOCI, before Income Tax (Expense) Credit	23	7	30
Income Tax (Expense) Credit	8	3	11
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	15	4	19
Net Current Period Other Comprehensive Income	15	4	19
Balance in AOCI as of March 31, 2016	$ (86)	$ (1,540)	$ (1,626)

4. RATE MATTERS

As discussed in KPCo's 2016 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo's 2016 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 2017 and updates KPCo's 2016 Annual Report.

Regulatory Assets Pending Final Regulatory Approval

Noncurrent Regulatory Assets	March 31, 2017	December 31, 2016
	(in thousands)	
Regulatory Assets Currently Not Earning a Return		
Storm Related Costs	$ 4,377	$ 4,377
Other Regulatory Assets Pending Final Regulatory Approval	68	52
Total Regulatory Assets Pending Final Regulatory Approval	$ 4,445	$ 4,429

If these costs are ultimately determined not to be recoverable, it could reduce future net income and cash flows and impact financial condition.

FERC Transmission Complaint and Proposed Modifications to Transmission Rates

In October 2016, several parties filed a joint complaint with the FERC that states the base return on common equity used by various AEP affiliates in calculating formula transmission rates under the PJM OATT is excessive and should be reduced from 10.99% to 8.32%, effective upon the date of the complaint. Management believes its financial statements adequately address the impact of the complaint. If the FERC orders revenue reductions as a result of the complaint, including refunds from the date of the complaint filing, it could reduce future net income and cash flows and impact financial condition.

Modifications to AEP East Transmission Companies Rates

In November 2016, certain AEP affiliates filed an application with the FERC to modify the PJM OATT formula transmission rate calculation, including an adjustment to recover a tax-related regulatory asset and a shift from historical to estimated expenses, with a proposed effective date of January 1, 2017. The filing proposed that the rates would be implemented based upon the date provided in the resulting FERC order. In March 2017, the FERC accepted the proposed modifications effective January 1, 2017, subject to refund, and set this matter for hearing and settlement procedures. Effective January 1, 2017, the AEP East Transmission Companies implemented the modified PJM OATT formula rates subject to refund which are based on projected 2017 calendar year financial activity and projected plant balances. If the FERC determines that any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, KPCo's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against KPCo cannot be predicted. Management accrues contingent liabilities only when management concludes that it is both probable that a liability has been incurred at the date of the financial statements and the amount of loss can be reasonably estimated. When management determines that it is not probable, but rather reasonably possible that a liability has been incurred at the date of the financial statements, management discloses such contingencies and the possible loss or range of loss if such estimate can be made. Any estimated range is based on currently available information and involves elements of judgment and significant uncertainties. Any estimated range of possible loss may not represent the maximum possible loss exposure. Circumstances change over time and actual results may vary significantly from estimates.

For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements. The Commitments, Guarantees and Contingencies note within KPCo's 2016 Annual Report should be read in conjunction with this report.

GUARANTEES

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

Letter of Credit

KPCo has $65 million of variable rate Pollution Control Bonds supported by a bilateral letter of credit for $66 million. The letter of credit matures in June 2017.

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of March 31, 2017, there were no material liabilities recorded for any indemnifications.

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

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, KPCo is committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance. As of March 31, 2017, the maximum potential loss for these lease agreements was $1.6 million assuming the fair value of the equipment is zero at the end of the lease term.

6. BENEFIT PLANS

KPCo participates in an AEP sponsored qualified pension plan and an unfunded nonqualified pension plan. Substantially all of KPCo's employees are covered by the qualified plan or both the qualified and nonqualified pension plans. KPCo also participates in OPEB plans sponsored by AEP to provide health and life insurance benefits for retired employees.

Components of Net Periodic Benefit Cost

The following table provides the components of KPCo's net periodic benefit cost (credit) for the plans for the three months ended March 31, 2017 and 2016:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2017	2016	2017	2016
	(in thousands)			
Service Cost	$ 729	$ 615	$ 83	$ 71
Interest Cost	1,787	1,872	539	538
Expected Return on Plan Assets	(2,575)	(2,533)	(960)	(989)
Amortization of Prior Service Cost (Credit)	12	13	(606)	(606)
Amortization of Net Actuarial Loss	719	736	348	287
Net Periodic Benefit Cost (Credit)	$ 672	$ 703	$ (596)	$ (699)

7. BUSINESS SEGMENTS

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

8. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of KPCo.

KPCo is exposed to certain market risks as a major power producer and participant in the electricity, natural gas, coal and emission allowance markets. 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. Management utilizes derivative instruments to manage these risks.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

The strategy surrounding the use of derivative instruments primarily focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. The risk management strategies also include the use of derivative instruments for trading purposes which focus on seizing market opportunities to create value driven by expected changes in the market prices of the commodities. To accomplish these objectives, KPCo primarily employs risk management contracts including physical and financial forward purchase-and-sale contracts and, to a lesser extent, OTC swaps and options. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

KPCo utilizes power, capacity, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. KPCo utilizes interest rate derivative contracts in order to manage the interest rate exposure associated with its commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. KPCo also utilizes derivative contracts to manage 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 the Board of Directors.

The following table represents the gross notional volume of KPCo's outstanding derivative contracts:

Notional Volume of Derivative Instruments

	Volume		
Primary Risk Exposure	**March 31, 2017**	**December 31, 2016**	**Unit of Measure**
	(in thousands)		
Commodity:			
Power	6,251	10,562	MWhs
Heating Oil and Gasoline	241	339	Gallons
Interest Rate	$ —	$ 22	USD

Cash Flow Hedging Strategies

KPCo utilizes cash flow hedges on certain derivative transactions for the purchase and sale of power ("Commodity") in order to manage the variable price risk related to forecasted purchases and sales. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and purchases. KPCo does not hedge all commodity price risk.

KPCo utilizes a variety of interest rate derivative transactions in order to manage interest rate risk exposure. KPCo also utilizes interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. KPCo does not hedge all interest rate exposure.

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

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities on the balance sheets 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 risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the March 31, 2017 and December 31, 2016 balance sheets, KPCo netted $4 thousand and $119 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $55 thousand and $134 thousand, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following tables represent the gross fair value of KPCo's derivative activity on the balance sheets:

Fair Value of Derivative Instruments
March 31, 2017

Balance Sheet Location	Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in thousands)	
Current Risk Management Assets	$ 3,819	$ (3,401)	$ 418
Long-term Risk Management Assets	1,078	(1,050)	28
Total Assets	4,897	(4,451)	446
Current Risk Management Liabilities	3,468	(3,397)	71
Long-term Risk Management Liabilities	1,121	(1,105)	16
Total Liabilities	4,589	(4,502)	87
Total MTM Derivative Contract Net Assets	$ 308	$ 51	$ 359

Fair Value of Derivative Instruments
December 31, 2016

Balance Sheet Location	Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in thousands)	
Current Risk Management Assets	$ 4,698	$ (4,241)	$ 457
Long-term Risk Management Assets	359	(359)	—
Total Assets	5,057	(4,600)	457
Current Risk Management Liabilities	4,306	(4,253)	53
Long-term Risk Management Liabilities	675	(362)	313
Total Liabilities	4,981	(4,615)	366
Total MTM Derivative Contract Net Assets	$ 76	$ 15	$ 91

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."
(c) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

The table below presents KPCo's activity of derivative risk management contracts:

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
	(in thousands)	
Electric Generation, Transmission and Distribution Revenues	$ 38	$ (163)
Sales to AEP Affiliates	—	290
Other Operation Expense	3	(25)
Maintenance Expense	5	(37)
Purchased Electricity for Resale	1,502	729
Regulatory Assets (a)	14	42
Regulatory Liabilities (a)	325	189
Total Gain on Risk Management Contracts	$ 1,887	$ 1,025

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

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

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

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on KPCo's statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on KPCo's statements of income depending on the relevant facts and circumstances. Certain derivatives that economically hedge future commodity risk are recorded in the same expense line item on the statements of income as that of the associated risk. However, unrealized and some realized gains and losses for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains), in accordance with the accounting guidance for "Regulated Operations."

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), KPCo initially reports the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the balance sheets until the period the hedged item affects Net Income. KPCo would recognize any hedge ineffectiveness as a regulatory asset (for losses) or a regulatory liability (for gains) if applicable.

Realized gains and losses on derivative contracts for the purchase and sale of power designated as cash flow hedges are included in Total Revenues or Purchased Electricity for Resale on KPCo's statements of income, or in Regulatory Assets or Regulatory Liabilities on KPCo's balance sheets, depending on the specific nature of the risk being hedged. During the three months ended March 31, 2017 and 2016, KPCo did not designate power derivatives as cash flow hedges.

KPCo reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on its balance sheets into Interest Expense on its statements of income in those periods in which hedged interest payments occur. During the three months ended March 31, 2017 and 2016, KPCo did not apply cash flow hedging to outstanding interest rate derivatives.

During the three months ended March 31, 2017 and 2016, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

For details on effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's balance sheets and the reasons for changes in cash flow hedges, see Note 3.

The impact of cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's balance sheets were:

	Interest Rate	
	March 31, 2017	December 31, 2016
	(in thousands)	
AOCI Loss Net of Tax	$ (25)	$ (41)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(25)	(40)

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, 2017, KPCo is not hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") its exposure to variability in future cash flows related to forecasted transactions.

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

Master agreements are typically used to facilitate the netting of cash flows associated with a single counterparty and may include collateral requirements. Collateral requirements in the form of cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. A counterparty is required 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, master agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, KPCo is obligated to post an additional amount of collateral if certain credit ratings decline below a specified rating threshold. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. KPCo has not experienced a downgrade below a specified rating threshold that would require the posting of additional collateral. There is no exposure relating to derivative contracts, however, there is exposure relating to RTOs, ISOs and non-derivative contracts. The following table represents KPCo's exposure if credit ratings were to decline below a specified rating threshold:

	March 31, 2017	December 31, 2016
	(in thousands)	
Amount of Collateral KPCo Would Have Been Required to Post Attributable to RTOs and ISOs	$ 1,280	$ 195
Amount of Collateral Attributable to Other Contracts	1,677	1,657

In addition, a majority of KPCo's non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation that is $50 million or greater. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering contractual netting arrangements:

	March 31, 2017	December 31, 2016
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 2	$ 25
Amount of Cash Collateral Posted	—	—
Additional Settlement Liability if Cross Default Provision is Triggered	2	—

9. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability. The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with established risk management policies as approved by the Finance Committee of AEP's Board of Directors. AEPSC's market risk oversight staff independently monitors risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (Regulated Risk Committee) various reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Vice Chairman, Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations and Chief Risk Officer.

For commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are nonbinding in nature but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A portion of the Level 3 instruments have been economically hedged which limits potential earnings volatility.

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of KPCo's Long-term Debt are summarized in the following table:

	March 31, 2017		December 31, 2016	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 867,345	$ 968,232	$ 867,164	$ 965,423

Fair Value Measurements of Financial Assets and Liabilities

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

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ —	$ 3,007	$ 696	$ (3,257)	$ 446
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ —	$ 2,901	$ 494	$ (3,308)	$ 87

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2016

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ —	$ 4,395	$ 616	$ (4,554)	$ 457
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ —	$ 4,517	$ 418	$ (4,569)	$ 366

(a) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(b) Substantially comprised of power contracts.

There were no transfers between Level 1 and Level 2 during the three months ended March 31, 2017 and 2016.

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, 2017	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of December 31, 2016	$ 198
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	1,381
Settlements	(1,730)
Changes in Fair Value Allocated to Regulated Jurisdictions (e)	353
Balance as of March 31, 2017	$ 202

Three Months Ended March 31, 2016	Net Risk Management Assets (Liabilities) (a) (in thousands)
Balance as of December 31, 2015	$ 2,246
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	382
Settlements	(1,739)
Transfers out of Level 3 (d)	22
Changes in Fair Value Allocated to Regulated Jurisdictions (e)	459
Balance as of March 31, 2016	$ 1,370

(a) Includes both affiliated and nonaffiliated transactions.
(b) Included in revenues on KPCo's statements of income.
(c) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(d) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(e) Relates to the net gains (losses) of those contracts that are not reflected on KPCo's statements of income. These net gains (losses) are recorded as regulatory assets/liabilities.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions:

Significant Unobservable Inputs
March 31, 2017

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$ 118	$ 46	Discounted Cash Flow	Forward Market Price	$ 19.36	$ 46.45	$ 34.61
FTRs	578	448	Discounted Cash Flow	Forward Market Price	—	3.52	1.00
Total	$ 696	$ 494					

Significant Unobservable Inputs
December 31, 2016

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$ 94	$ 81	Discounted Cash Flow	Forward Market Price	$ 19.68	$ 48.55	$ 36.34
FTRs	522	337	Discounted Cash Flow	Forward Market Price	0.01	8.91	0.96
Total	$ 616	$ 418					

(a) Represents market prices in dollars per MWh.

The following table provides sensitivity of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts and FTRs as of March 31, 2017 and December 31, 2016:

Sensitivity of Fair Value Measurements

Significant Unobservable Input	Position	Change in Input	Impact on Fair Value Measurement
Forward Market Price	Buy	Increase (Decrease)	Higher (Lower)
Forward Market Price	Sell	Increase (Decrease)	Lower (Higher)

10. INCOME TAXES

AEP System Tax Allocation Agreement

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

Federal and State Income Tax Audit Status

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2011. The IRS examination of years 2011, 2012 and 2013 started in April 2014. AEP and subsidiaries received a Revenue Agents Report in April 2016, completing the 2011 through 2013 audit cycle indicating an agreed upon audit. The 2011 through 2013 audit was submitted to the Congressional Joint Committee on Taxation for approval. The Joint Committee referred the audit back to the IRS exam team for further consideration. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to materially impact net income.

KPCo and other AEP subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns. KPCo and other AEP subsidiaries are currently under examination in several state and local jurisdictions. However, it is possible that previously filed tax returns have positions that may be challenged by these tax authorities. Management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income. KPCo is no longer subject to state or local income tax examinations by tax authorities for years before 2009.

11. FINANCING ACTIVITIES

Long-term Debt

KPCo did not have any long-term debt issuances or retirements during the first three months of 2017.

Dividend Restrictions

KPCo pays dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of KPCo to transfer funds to Parent in the form of dividends.

Federal Power Act

The Federal Power Act prohibits KPCo from participating "in the making or paying of any dividends of such public utility from any funds properly included in capital account." This restriction does not limit the ability of KPCo to pay dividends out of retained earnings.

Leverage Restrictions

Pursuant to the credit agreement leverage restrictions, KPCo must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%.

Corporate Borrowing Program – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding borrowings from the Utility Money Pool as of March 31, 2017 and December 31, 2016 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, 2017 are described in the following table:

Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Borrowings from the Utility Money Pool as of March 31, 2017	Authorized Short-Term Borrowing Limit
		(in thousands)			
$ 13,636	$ 20,852	$ 4,438	$ 6,338	$ 12,172	$ 225,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool are summarized in the following table:

Three Months Ended March 31,	Maximum Interest Rate for Funds Borrowed from the Utility Money Pool	Minimum Interest Rate for Funds Borrowed from the Utility Money Pool	Maximum Interest Rate for Funds Loaned to the Utility Money Pool	Minimum Interest Rate 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
2017	1.27%	0.95%	1.15%	0.92%	1.14%	0.97%
2016	0.83%	0.69%	—%	—%	0.73%	—%

Securitized Accounts Receivables – AEP Credit

Under a sale of receivables arrangement, KPCo sells, without recourse, certain of its customer accounts receivable and accrued unbilled revenue balances to AEP Credit and is charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for KPCo's receivables. The costs of customer accounts receivable sold are reported in Other Operation expense on KPCo's statements of income. KPCo manages and services its accounts receivable sold.

AEP Credit's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables and expires in June 2018.

KPCo's amounts of accounts receivable and accrued unbilled revenues sold under the sale of receivables agreement were $47 million and $49 million as of March 31, 2017 and December 31, 2016, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold were $793 thousand and $736 thousand for the three months ended March 31, 2017 and 2016, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit were $161 million and $155 million for the three months ended March 31, 2017 and 2016, respectively.

Kentucky Power Company
AEPSC Chages by FERC Account, Allocation Factor and Allocation Type, net of share billed to Co-Owner
For 2014,2015,2016 and Test Year Ended February 2017

American Electric Power Service Corporation (AEPSC) is a wholly owned subsidiary of AEP and is the Centralized Service Company for the AEP System. AEPSC's activities are authorized by the FERC under the Public Utilities Holding Company Act of 2005. AEPSC performs, at cost, various corporate support services for subsidiaries of AEP, including Kentucky Power.

AEPSC transactions are accounted for through a work order system as required by the FERC. Costs for support services are accumulated in work orders and are billed to the company or companies benefiting from the service. Accounting within each work order is in accordance with the FERC Uniform System of Accounts. The costs for services benefiting only one company are directly assigned and are billed 100% to that company. Where services benefit more than one company, the costs for those services are allocated to the benefiting companies using an approved allocation factor. The allocation factor for any given allocation of costs is selected for use because it best reflects the cost driver associated with the service provided.

The FERC monitors the factors used for allocations, through required annual reporting, and can audit the validity of each factor. All services are billed at cost, with no profit charged, as required by the FERC's "at cost" rules.

			2014					2015					2016					TEST YEAR				
Account Type	FERC Account	Allocation Factor	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net
Cost of Service	5000 - Oper Supervision & Engineering	08 - Number of Electric Retail Cust												-	-				-	-		
		09 - Number of Employees		(7,295)	(7,295)				30,802	30,802				(26,102)	(26,102)				(21,965)	(21,965)		
		17 - Number of Purchase Orders		149	149				186	186				0	0				30	30		
		26 - Number of Stores Transactions																	1,874	1,874		
		28 - Number of Trans Pole Miles		261	261				218	218				301	301				287	287		
		33 - Number of Workstations		122	122				14,701	14,701				41,500	41,500				41,433	41,433		
		39 - 100% to One Company	1,432,546		1,432,546			1,670,747		1,670,747			1,352,823		1,352,823			1,721,836		1,721,836		
		40 - Equal Share Ratio		16,059	16,059				45,243	45,243				17,636	17,636				6,396	6,396		
		48 - MW Generating Capability		3,366,204	3,366,204				2,921,007	2,921,007				3,006,566	3,006,566				3,071,560	3,071,560		
		49 - MWH's Generation		131,715	131,715				74,617	74,617				110,612	110,612				117,587	117,587		
		57 - Tons of Fuel Acquired		19,566	19,566				16,381	16,381				20,842	20,842				21,331	21,331		
		58 - Total Assets		19,565	19,565				18,757	18,757				43,941	43,941				39,143	39,143		
		60 - AEPSC Bill less Indir and Int		454	454				(878)	(878)				283	283				290	290		
		61 - Total Fixed Assets		766	766				7,533	7,533				113	113				113	113		
		63 - Total Gross Utility Plant		1,262	1,262				82	82				1,168	1,168				1,532	1,532		
		70 - No Nonelectric OAR Invoices							(20,518)	(20,518)												
	5000 - Oper Supervision & Engineering Total		1,432,546	3,548,828	4,981,374	(1,572,504)	3,408,870	1,670,747	3,108,130	4,778,877	(1,744,283)	3,034,595	1,352,823	3,216,861	4,569,683	(1,803,372)	2,766,312	1,721,836	3,279,610	5,001,446	(1,885,495)	3,115,952
	5010 - Fuel	09 - Number of Employees		956	956				4,134	4,134				2,808	2,808				4,087	4,087		
		28 - Number of Trans Pole Miles		-	-																	
		39 - 100% to One Company	37,544		37,544			58,234		58,234			139,255		139,255			176,257		176,257		
		48 - MW Generating Capability		20,643	20,643				18,870	18,870				9,777	9,777				12,575	12,575		
		51 - Past 3 Mo MMBTU's Burned (Tot)		2,680	2,680				160	160												
		52 - Past 3 Mo MMBTU Burned (Coal)							332	332				68	68				39	39		
		53 - Past 3 Mo MMBTU (Gas)												216	216				244	244		
		55 - Past 3 MMBTU Burned (Solid)		143	143				35	35												
		58 - Total Assets		842	842				94	94				106	106				109	109		
		60 - AEPSC Bill less Indir and Int		(56)	(56)				28	28				38	38				(153)	(153)		
		63 - Total Gross Utility Plant		574	574				133	133				7	7							
		64 - Member/Peak Load							1	1												
	5010 - Fuel Total		37,544	25,783	63,327	(18,346)	44,981	58,234	23,787	82,021	(18,351)	63,670	139,255	13,019	152,274	(15,499)	136,775	176,257	16,900	193,157	(19,332)	173,825
	5020 - Steam Expenses	39 - 100% to One Company	58,481		58,481			73,367		73,367			64,081		64,081			60,660		60,660		
		48 - MW Generating Capability		14	14				(97)	(97)				(2)	(2)				74	74		
		52 - Past 3 Mo MMBTU Burned (Coal)		14,990	14,990				4,691	4,691				2,250	2,250				1,768	1,768		
	5020 - Steam Expenses Total		58,481	15,004	73,485	(29,794)	43,691	73,367	4,593	77,960	(29,250)	48,710	64,081	2,249	66,330	(24,886)	41,444	60,660	1,841	62,501	(23,443)	39,058
	5050 - Electric Expenses	28 - Number of Trans Pole Miles							-	-				-	-				-	-		
		39 - 100% to One Company						403		403			3,820		3,820			3,820		3,820		
		48 - MW Generating Capability		38	38				(44)	(44)				(0)	(0)				(0)	(0)		
	5050 - Electric Expenses Total			38	38	(11)	27	403	(44)	359	13	372	3,820	(0)	3,820	-	3,820	3,820	(0)	3,820	-	3,820
	5060 - Misc Steam Power Expenses	08 - Number of Electric Retail Cust		3	3				(12)	(12)				(0)	(0)				4	4		
		09 - Number of Employees												4	4				180	180		
		28 - Number of Trans Pole Miles		24	24				20	20				6	6				57	57		
		37 - AEPSC Past 3 Months Total Bill		16,983	16,983				598	598				270	270							
		39 - 100% to One Company	21,525		21,525																	
		39 - 100% to One Company	82,141		82,141			134,712		134,712			286,775		286,775			21,906		21,906		
		40 - Equal Share Ratio		3,517	3,517				2,000	2,000				1,748	1,748				1,748	1,748		
		48 - MW Generating Capability		70,627	70,627				14,924	14,924				(2,166)	(2,166)				4,023	4,023		
		52 - Past 3 Mo MMBTU Burned (Coal)		731	731				1,317	1,317												
		58 - Total Assets		31,648	31,648				24,815	24,815				41,876	41,876				44,101	44,101		
		60 - AEPSC Bill less Indir and Int		191	191				(79)	(79)				190	190				223	223		
		61 - Total Fixed Assets		1,152	1,152				1,002	1,002				1,035	1,035				827	827		
	5060 - Misc Steam Power Expenses Total		103,666	124,877	228,543	(169,008)	59,535	134,712	44,585	179,298	(206,088)	(26,790)	286,775	42,963	329,739	(44,664)	285,075	21,906	51,162	73,068	(152,581)	(79,513)
	5070 - Rents	28 - Number of Trans Pole Miles		-	-																	
	5070 - Rents Total			-	-	-	-				-	-				-	-				-	-
	5080 - Operation Supplies and Expenses	09 - Number of Employees							0	0												
		33 - Number of Workstations												19	19				19	19		
	5080 - Operation Supplies and Expenses Total					-	-		0	0	-	0		19	19	-	19		19	19	-	19
	5100 - Maint Supv & Engineering	09 - Number of Employees		2,474	2,474				633	633				255	255				255	255		
		17 - Number of Purchase Orders		3	3																	
		28 - Number of Trans Pole Miles												(0)	(0)				4	4		
		39 - 100% to One Company	185,301		185,301			279,669		279,669			242,926		242,926			260,332		260,332		
		40 - Equal Share Ratio		11,889	11,889				1,264	1,264				2,223	2,223				2,070	2,070		
		48 - MW Generating Capability		189,743	189,743				202,245	202,245				248,844	248,844				268,184	268,184		
		49 - MWH's Generation		736	736				524	524				424	424				424	424		
		58 - Total Assets		396	396				2,176	2,176				2,263	2,263				9,073	9,073		
		60 - AEPSC Bill less Indir and Int		68	68				(82)	(82)				(1)	(1)							
		63 - Total Gross Utility Plant		16	16																	
	5100 - Maint Supv & Engineering Total		185,301	205,323	390,624	(125,238)	265,386	279,669	206,760	486,429	(195,225)	291,205	242,926	254,009	496,935	(188,986)	307,949	260,332	280,011	540,343	(203,293)	337,050
	5110 - Maintenance of Structures	08 - Number of Electric Retail Cust		(1)	(1)																	
		28 - Number of Trans Pole Miles		0	0				-	-				-	-				-	-		
		39 - 100% to One Company	569,631		569,631			303,254		303,254			437,886		437,886			384,420		384,420		
		48 - MW Generating Capability		2,156	2,156				(1,053)	(1,053)				(502)	(502)				(925)	(925)		
		60 - AEPSC Bill less Indir and Int		1	1				0	0				(1)	(1)							
	5110 - Maintenance of Structures Total		569,631	2,155	571,786	(233,759)	338,027	303,254	(1,053)	302,202	(113,369)	188,833	437,886	(503)	437,383	(208,041)	229,343	384,420	(925)	383,494	(149,517)	233,977
	5120 - Maintenance of Boiler Plant	28 - Number of Trans Pole Miles		2	2				(3)	(3)				(1)	(1)				(21)	(21)		
		39 - 100% to One Company	1,389,141		1,389,141			1,636,549		1,636,549			909,387		909,387			737,324		737,324		
		48 - MW Generating Capability		13,933	13,933				(10,215)	(10,215)				1,395	1,395				(9,975)	(9,975)		
		60 - AEPSC Bill less Indir and Int		8	8				(4)	(4)				(2)	(2)				2	2		
	5120 - Maintenance of Boiler Plant Total		1,389,141	13,942	1,403,083	(647,100)	755,983	1,636,549	(10,222)	1,626,327	(622,494)	1,003,833	909,387	1,391	910,778	(309,970)	600,808	737,324	(9,994)	727,330	(253,404)	473,926
	5130 - Maintenance of Electric Plant	08 - Number of Electric Retail Cust		-	-																	
		28 - Number of Trans Pole Miles		78	78				73	73				(37)	(37)				(35)	(35)		
		39 - 100% to One Company	717,437		717,437			2,803,941		2,803,941			1,266,116		1,266,116			1,203,953		1,203,953		
		48 - MW Generating Capability		5,870	5,870				791	791				(980)	(980)				(1,143)	(1,143)		
		60 - AEPSC Bill less Indir and Int							-	-												
	5130 - Maintenance of Electric Plant Total		717,437	5,948	723,385	(323,080)	400,304	2,803,941	864	2,804,805	(1,194,746)	1,610,059	1,266,116	(1,017)	1,265,099	(326,932)	938,167	1,203,953	(1,178)	1,202,775	(415,199)	787,576
	5140 - Maintenance of Misc Steam Plt	08 - Number of Electric Retail Cust		(22)	(22)									-	-				(44)	(44)		
		28 - Number of Trans Pole Miles		(9)	(9)				0	0				-	-				(7)	(7)		
		39 - 100% to One Company	136,791		136,791			67,879		67,879			303,162		303,162			308,466		308,466		
		48 - MW Generating Capability		692	692				(949)	(949)				540	540				1,939	1,939		
		60 - AEPSC Bill less Indir and Int		0	0				28	28				(28)	(28)				(103)	(103)		
	5140 - Maintenance of Misc Steam Plt Total		136,791	661	137,452	(65,103)	72,350	67,879	(922)	66,957	(20,469)	46,488	303,162	512	303,675	(139,020)	164,655	308,466	1,785	310,251	(142,047)	168,204
	5170 - Oper Supervision & Engineering	28 - Number of Trans Pole Miles		-	-				-	-				-	-				-	-		
		48 - MW Generating Capability		24	24				(46)	(46)				72	72				178	178		
		60 - AEPSC Bill less Indir and Int		-	-																	
	5170 - Oper Supervision & Engineering Total			24	24	-	24		(46)	(46)	-	(46)		72	72	-	72		178	178	-	178
	5200 - Steam Expenses	09 - Number of Employees							12	12				137	137				137	137		
		28 - Number of Trans Pole Miles												-	-				-	-		
		58 - Total Assets		104	104									59	59				59	59		
	5200 - Steam Expenses Total			104	104	-	104		12	12	-	12		196	196	-	196		196	196	-	196
	5240 - Misc Nuclear Power Expenses	08 - Number of Electric Retail Cust		-	-				-	-				-	-				-	-		
		48 - MW Generating Capability		275	275				(9)	(9)				32	32				8	8		
		58 - Total Assets							982	982				3	3							
		60 - AEPSC Bill less Indir and Int		(0)	(0)				53	53				(57)	(57)				(41)	(41)		
		63 - Total Gross Utility Plant																	33	33		
	5240 - Misc Nuclear Power Expenses Total			275	275	-	275		1,026	1,026	-	1,026		(21)	(21)	-	(21)		(1)	(1)	-	(1)
	5280 - Maint Supv & Engineering	28 - Number of Trans Pole Miles		-	-																	
		39 - 100% to One Company						-		-												
		48 - MW Generating Capability		1,353	1,353				959	959				1,568	1,568				1,774	1,774		
		60 - AEPSC Bill less Indir and Int		9	9				(15)	(15)				(1)	(1)				532	532		
		63 - Total Gross Utility Plant		74	74																	
	5280 - Maint Supv & Engineering Total			1,436	1,436	-	1,436	-	944	944	-	944		1,568	1,568	-	1,568		2,306	2,306	-	2,306
	5300 - Maint of Reactor Plant Equip	06 - Number of Commercial Customers												68	68				68	68		
		09 - Number of Employees		471	471				1	1												

Kentucky Power Company
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For 2014,2015,2016 and Test Year Ended February 2017

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The FERC monitors the factors used for allocations, through required annual reporting, and can audit the validity of each factor. All services are billed at cost, with no profit charged, as required by the FERC's "at cost" rules.

			2014					2015					2016					TEST YEAR				
Account Type	FERC Account	Allocation Factor	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net
		28 - Number of Trans Pole Miles		(1)	(1)				-	-				29	29				(66)	(66)		
		48 - MW Generating Capability		2	2				(0)	(0)				967	967				(1,607)	(1,607)		
		58 - Total Assets							12	12												
		60 - AEPSC Bill less Indir and Int							1	1				(1)	(1)							
	5300 - Maint of Reactor Plant Equip Total			472	472	-	472		13	13	-	13		1,064	1,064	-	1,064		(1,605)	(1,605)	-	(1,605)
	5310 - Maintenance of Electric Plant	28 - Number of Trans Pole Miles		28	28				(28)	(28)												
		48 - MW Generating Capability		-	-				0	0				1,748	1,748				7,194	7,194		
	5310 - Maintenance of Electric Plant Total			28	28	-	28		(28)	(28)	-	(28)		1,748	1,748	-	1,748		7,194	7,194	-	7,194
	5320 - Maint of Misc Nuclear Plant	28 - Number of Trans Pole Miles							-	-												
		48 - MW Generating Capability		-	-				-	-				40	40				0	0		
		58 - Total Assets							1	1									7	7		
		60 - AEPSC Bill less Indir and Int		-	-																	
	5320 - Maint of Misc Nuclear Plant Total			-	-	-	-		1	1	-	1		40	40	-	40		7	7	-	7
	5350 - Oper Supervision & Engineering	28 - Number of Trans Pole Miles							9	9												
		39 - 100% to One Company						960		960			32		32			53		53		
		48 - MW Generating Capability		(550)	(550)				15	15				256	256				916	916		
	5350 - Oper Supervision & Engineering Total			(550)	(550)	-	(550)	960	23	983	-	983	32	256	288	-	288	53	916	968	-	968
	5370 - Hydraulic Expenses	48 - MW Generating Capability		(103)	(103)				-	-				-	-				-	-		
	5370 - Hydraulic Expenses Total			(103)	(103)	-	(103)		-	-	-	-		-	-	-	-		-	-	-	-
	5390 - Misc Hydr Power Generation Exp	08 - Number of Electric Retail Cust		-	-																	
		28 - Number of Trans Pole Miles							-	-												
		48 - MW Generating Capability		(505)	(505)																	
		58 - Total Assets		1	1																	
		60 - AEPSC Bill less Indir and Int		7	7				7	7				(18)	(18)				(4)	(4)		
	5390 - Misc Hydr Power Generation Exp Total			(496)	(496)	-	(496)		7	7	-	7		(18)	(18)	-	(18)		(4)	(4)	-	(4)
	5400 - Rents	48 - MW Generating Capability												-	-				-	-		
		58 - Total Assets												365	365				365	365		
	5400 - Rents Total					-	-				-	-		365	365	-	365		365	365	-	365
	5420 - Maintenance of Structures	28 - Number of Trans Pole Miles							-	-				-	-				-	-		
		48 - MW Generating Capability		(73)	(73)									30	30				86	86		
		60 - AEPSC Bill less Indir and Int		(11)	(11)				41	41				(70)	(70)				(109)	(109)		
	5420 - Maintenance of Structures Total			(84)	(84)	-	(84)		41	41	-	41		(40)	(40)	-	(40)		(23)	(23)	-	(23)
	5430 - Maint Rsrvoirs,Dams&Wtrways	28 - Number of Trans Pole Miles		(4)	(4)				(0)	(0)				-	-				-	-		
		48 - MW Generating Capability		(77)	(77)				15	15				283	283				509	509		
	5430 - Maint Rsrvoirs,Dams&Wtrways Total			(81)	(81)	-	(81)		15	15	-	15		283	283	-	283		509	509	-	509
	5440 - Maintenance of Electric Plant	08 - Number of Electric Retail Cust		26	26				(26)	(26)				0	0				(59)	(59)		
		28 - Number of Trans Pole Miles		(5)	(5)				6	6				(6)	(6)				(114)	(114)		
		48 - MW Generating Capability		(94)	(94)				64	64				(64)	(64)				3	3		
	5440 - Maintenance of Electric Plant Total			(73)	(73)	-	(73)		44	44	-	44		(70)	(70)	-	(70)		(170)	(170)	-	(170)
	5450 - Maint of Misc Hydraulic Plant	48 - MW Generating Capability		(18)	(18)																	
	5450 - Maint of Misc Hydraulic Plant Total			(18)	(18)	-	(18)				-	-				-	-				-	-
	5460 - Oper Supervision & Engineering	48 - MW Generating Capability		343	343				141	141				(230)	(230)				(423)	(423)		
		60 - AEPSC Bill less Indir and Int		2	2				(2)	(2)												
	5460 - Oper Supervision & Engineering Total			344	344	-	344		139	139	-	139		(230)	(230)	-	(230)		(423)	(423)	-	(423)
	5470 - Fuel	48 - MW Generating Capability		76	76				(58)	(58)				(35)	(35)				(62)	(62)		
		60 - AEPSC Bill less Indir and Int		(10)	(10)				6	6				(10)	(10)				(35)	(35)		
	5470 - Fuel Total			66	66	-	66		(51)	(51)	-	(51)		(44)	(44)	-	(44)		(97)	(97)	-	(97)
	5480 - Generation Expenses	48 - MW Generating Capability		2	2									5	5				5	5		
	5480 - Generation Expenses Total			2	2	-	2				-	-		5	5	-	5		5	5	-	5
	5490 - Misc Other Pwer Generation Exp	28 - Number of Trans Pole Miles		-	-																	
		48 - MW Generating Capability							-	-				-	-				-	-		
	5490 - Misc Other Pwer Generation Exp Total			-	-	-	-		-	-	-	-		-	-	-	-		-	-	-	-
	5530 - Maintenance of Generating Plt	28 - Number of Trans Pole Miles		5	5				(5)	(5)				(0)	(0)				(24)	(24)		
		48 - MW Generating Capability		1,003	1,003				(809)	(809)				(31)	(31)				(340)	(340)		
		60 - AEPSC Bill less Indir and Int							2	2				(2)	(2)							
	5530 - Maintenance of Generating Plt Total			1,008	1,008	-	1,008		(813)	(813)	-	(813)		(33)	(33)	-	(33)		(364)	(364)	-	(364)
	5550 - Purchased Power	28 - Number of Trans Pole Miles		(0)	(0)																	
		39 - 100% to One Company	327		327			351		351												
		48 - MW Generating Capability		114	114				(97)	(97)				(5)	(5)				4	4		
	5550 - Purchased Power Total		327	114	441	-	441	351	(97)	254	-	254		(5)	(5)	-	(5)		4	4	-	4
	5560 - Sys Control & Load Dispatching	09 - Number of Employees		9	9				43	43				0	0				0	0		
		28 - Number of Trans Pole Miles		1,728	1,728				325	325				6	6				1	1		
		33 - Number of Workstations							0	0												
		39 - 100% to One Company						-		-												
		48 - MW Generating Capability		10,536	10,536				4,465	4,465				(3,265)	(3,265)				4,804	4,804		
		49 - MWH's Generation		484,161	484,161				461,288	461,288				503,690	503,690				561,758	561,758		
		58 - Total Assets		12,860	12,860				280	280				22	22				37	37		
		60 - AEPSC Bill less Indir and Int		(18)	(18)				(3)	(3)				8	8				-	-		
		61 - Total Fixed Assets		18	18																	
		63 - Total Gross Utility Plant		630	630				40	40				35	35				27	27		
		64 - Member/Peak Load							12,455	12,455				15,136	15,136				13,711	13,711		
	5560 - Sys Control & Load Dispatching Total			509,923	509,923	-	509,923	-	478,893	478,893	-	478,893		515,633	515,633	-	515,633		580,338	580,338	-	580,338
	5570 - Other Expenses	08 - Number of Electric Retail Cust		13	13																	
		09 - Number of Employees		1,264	1,264				835	835				40	40				44	44		
		11 - Number of GL Transactions												78	78				78	78		
		28 - Number of Trans Pole Miles		-	-				97	97												
		32 - Number of Vendor Invoice Pay		(413)	(413)																	
		39 - 100% to One Company	45,058		45,058			75,884		75,884			12,742		12,742			7,211		7,211		
		48 - MW Generating Capability		51,062	51,062				19,857	19,857				33,933	33,933				38,141	38,141		
		49 - MWH's Generation		299	299				3,105	3,105				9,325	9,325				14,481	14,481		
		51 - Past 3 Mo MMBTU's Burned (Tot)		104,570	104,570				135,766	135,766												
		52 - Past 3 Mo MMBTU Burned (Coal)		66,738	66,738				34,082	34,082				36,675	36,675				38,552	38,552		
		58 - Total Assets		13,841	13,841				1,924	1,924				11,428	11,428				14,462	14,462		
		60 - AEPSC Bill less Indir and Int		234	234				(191)	(191)				170	170				838	838		
		63 - Total Gross Utility Plant		3,888	3,888				261	261												
		64 - Member/Peak Load		1,331,899	1,331,899				1,330,068	1,330,068				1,256,896	1,256,896				1,221,647	1,221,647		
	5570 - Other Expenses Total		45,058	1,573,397	1,618,455	-	1,618,455	75,884	1,525,804	1,601,689	-	1,601,689	12,742	1,348,545	1,361,286	-	1,361,286	7,211	1,328,242	1,335,454	-	1,335,454
	5600 - Oper Supervision & Engineering	08 - Number of Electric Retail Cust		0	0				-	-				16	16				58	58		
		09 - Number of Employees		278,850	278,850				25,197	25,197				43,761	43,761				38,502	38,502		
		11 - Number of GL Transactions		801	801																	
		15 - Number of Non UMWA Employees		2	2																	
		17 - Number of Purchase Orders		142	142				103	103				55	55				35	35		
		26 - Number of Stores Transactions							5	5												
		27 - Number of Telephones		3	3																	
		28 - Number of Trans Pole Miles		626,202	626,202				711,953	711,953				775,368	775,368				712,573	712,573		
		32 - Number of Vendor Invoice Pay		389	389																	
		33 - Number of Workstations		10,148	10,148				330	330				429	429				394	394		
		39 - 100% to One Company	9,084		9,084			102,255		102,255			144,531		144,531			163,529		163,529		
		46 - Level of Const-Transmission		1	1									0	0				0	0		
		48 - MW Generating Capability		1,687	1,687				(1,000)	(1,000)				2,613	2,613				4,064	4,064		
		58 - Total Assets		141,745	141,745				230,299	230,299				355,218	355,218				499,818	499,818		
		60 - AEPSC Bill less Indir and Int		(326)	(326)				(127)	(127)				68	68				(216)	(216)		
		61 - Total Fixed Assets		14,257	14,257				16,201	16,201				15,859	15,859				11,575	11,575		
		63 - Total Gross Utility Plant		361	361				87	87				1,069	1,069				1,443	1,443		
	5600 - Oper Supervision & Engineering Total		9,084	1,074,260	1,083,344	-	1,083,344	102,255	983,049	1,085,304	-	1,085,304	144,531	1,194,457	1,338,987	-	1,338,987	163,529	1,268,246	1,431,775	-	1,431,775
	5611 - Load Dispatch - Reliability	28 - Number of Trans Pole Miles		7,474	7,474				5,541	5,541				8,544	8,544				7,719	7,719		
		39 - 100% to One Company	90		90			51		51			3		3			0		0		
		58 - Total Assets																	398	398		
		61 - Total Fixed Assets							40	40												
	5611 - Load Dispatch - Reliability Total		90	7,474	7,564	-	7,564	51	5,581	5,632	-	5,632	3	8,544	8,547	-	8,547	0	8,118	8,118	-	8,118
	5612 - Load Dispatch-Mntr&Op TransSys	09 - Number of Employees		82,638	82,638				10,264	10,264				7,394	7,394				6,047	6,047		
		17 - Number of Purchase Orders		9	9				0	0				22	22				22	22		

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			2014					2015					2016					TEST YEAR				
Account Type	FERC Account	Allocation Factor	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net
		28 - Number of Trans Pole Miles		755,952	755,952				791,890	791,890				742,410	742,410				618,595	618,595		
		33 - Number of Workstations												4	4				4	4		
		39 - 100% to One Company	38,050		38,050			15,084		15,084			198		198			133		133		
		58 - Total Assets		275	275				505	505				27,680	27,680				97,177	97,177		
		60 - AEPSC Bill less Indir and Int		(1)	(1)				-	-												
		61 - Total Fixed Assets		615	615				2,416	2,416				1,179	1,179				1,835	1,835		
		63 - Total Gross Utility Plant		42	42																	
	5612 - Load Dispatch-Mntr&Op TransSys Total		38,050	839,530	877,580	-	877,580	15,084	805,075	820,159	-	820,159	198	778,689	778,887	-	778,887	133	723,680	723,813	-	723,813
	5615 - Reliability,Plng&Stds Develop	09 - Number of Employees		1,262	1,262				65	65				48	48				48	48		
		28 - Number of Trans Pole Miles		81,426	81,426				70,226	70,226				53,439	53,439				51,085	51,085		
		33 - Number of Workstations		2,413	2,413				31	31				19	19				17	17		
		39 - 100% to One Company	622		622			1,137		1,137			39		39			0		0		
		40 - Equal Share Ratio							82	82				94	94				40	40		
		43 - KWH Sales		227	227																	
		58 - Total Assets		1,562	1,562				3,790	3,790				1,872	1,872				4,861	4,861		
		61 - Total Fixed Assets		28,575	28,575				64,504	64,504				61,152	61,152				59,508	59,508		
	5615 - Reliability,Plng&Stds Develop Total		622	115,465	116,087	-	116,087	1,137	138,698	139,836	-	139,836	39	116,624	116,663	-	116,663	0	115,561	115,561	-	115,561
	5616 - Transmission service studies	09 - Number of Employees							5	5												
		28 - Number of Trans Pole Miles							-	-												
		39 - 100% to One Company						0		0												
		58 - Total Assets							104	104												
	5616 - Transmission service studies Total					-	-	0	110	110	-	110				-	-				-	-
	5620 - Station Expenses	28 - Number of Trans Pole Miles		517	517				384	384				349	349				(144)	(144)		
		39 - 100% to One Company	17,520		17,520			66,416		66,416			40,665		40,665			42,040		42,040		
		58 - Total Assets							175,679	175,679				127,784	127,784				119,833	119,833		
		60 - AEPSC Bill less Indir and Int							-	-												
	5620 - Station Expenses Total		17,520	517	18,037	-	18,037	66,416	176,063	242,479	-	242,479	40,665	128,133	168,798	-	168,798	42,040	119,689	161,729	-	161,729
	5630 - Overhead Line Expenses	09 - Number of Employees												75	75				114	114		
		28 - Number of Trans Pole Miles		7,414	7,414				3,873	3,873				2,804	2,804				2,699	2,699		
		39 - 100% to One Company	0		0			30,650		30,650			44,356		44,356			45,475		45,475		
		58 - Total Assets							1,588	1,588				1,912	1,912				2,830	2,830		
	5630 - Overhead Line Expenses Total		0	7,414	7,414	-	7,414	30,650	5,461	36,111	-	36,111	44,356	4,791	49,147	-	49,147	45,475	5,644	51,119	-	51,119
	5640 - Underground Line Expenses	28 - Number of Trans Pole Miles		7	7				(7)	(7)												
	5640 - Underground Line Expenses Total			7	7	-	7		(7)	(7)	-	(7)				-	-				-	-
	5660 - Misc Transmission Expenses	08 - Number of Electric Retail Cust		(10)	(10)				5	5				(1)	(1)				(138)	(138)		
		09 - Number of Employees		62,808	62,808				8,430	8,430				21,400	21,400				21,499	21,499		
		17 - Number of Purchase Orders		24	24				111	111				226	226				205	205		
		27 - Number of Telephones							72	72												
		28 - Number of Trans Pole Miles		281,183	281,183				316,989	316,989				351,125	351,125				320,075	320,075		
		32 - Number of Vendor Invoice Pay		19	19									0	0				0	0		
		33 - Number of Workstations		36,489	36,489				1,713	1,713				1,891	1,891				1,731	1,731		
		39 - 100% to One Company	436,248		436,248			106,849		106,849			5,506		5,506			5,506		5,506		
		39 - 100% to One Company	51,971		51,971			80,026		80,026			175,553		175,553			50,495		50,495		
		40 - Equal Share Ratio		68	68				113	113				56	56				64	64		
		46 - Level of Const-Transmission		0	0																	
		48 - MW Generating Capability		3	3				3	3				142	142				213	213		
		58 - Total Assets		53,608	53,608				484,918	484,918				471,836	471,836				499,085	499,085		
		60 - AEPSC Bill less Indir and Int		377	377				(84)	(84)				(394)	(394)				(681)	(681)		
		61 - Total Fixed Assets		9,404	9,404				24,652	24,652				17,106	17,106				18,548	18,548		
		63 - Total Gross Utility Plant							1	1				1,628	1,628				1,637	1,637		
	5660 - Misc Transmission Expenses Total		488,219	443,972	932,192	-	932,192	186,875	836,923	1,023,798	-	1,023,798	181,058	865,015	1,046,073	-	1,046,073	56,001	862,239	918,240	-	918,240
	5670 - Rents	28 - Number of Trans Pole Miles		-	-									-	-				(5)	(5)		
	5670 - Rents Total			-	-	-	-				-	-		-	-	-	-		(5)	(5)	-	(5)
	5680 - Maint Supv & Engineering	08 - Number of Electric Retail Cust		-	-				17	17				(9)	(9)				(161)	(161)		
		09 - Number of Employees		378	378				20	20				11	11				10	10		
		28 - Number of Trans Pole Miles		69,522	69,522				541	541				3,386	3,386				2,185	2,185		
		39 - 100% to One Company	345		345			2,680		2,680			2,755		2,755			2,756		2,756		
		48 - MW Generating Capability		0	0									208	208				208	208		
		58 - Total Assets							23,793	23,793				20,958	20,958				19,898	19,898		
		60 - AEPSC Bill less Indir and Int		5	5				(5)	(5)				(0)	(0)				8	8		
	5680 - Maint Supv & Engineering Total		345	69,905	70,250	-	70,250	2,680	24,366	27,047	-	27,047	2,755	24,554	27,310	-	27,310	2,756	22,148	24,904	-	24,904
	5690 - Maintenance of Structures	28 - Number of Trans Pole Miles		15	15				(10)	(10)				29	29				150	150		
		39 - 100% to One Company						24		24			2,802		2,802			2,256		2,256		
		58 - Total Assets							4,581	4,581				2,730	2,730				3,671	3,671		
	5690 - Maintenance of Structures Total			15	15	-	15	24	4,571	4,595	-	4,595	2,802	2,759	5,561	-	5,561	2,256	3,821	6,077	-	6,077
	5691 - Maint of Computer Hardware	09 - Number of Employees		393	393																	
		28 - Number of Trans Pole Miles		603	603				13	13				804	804				937	937		
		33 - Number of Workstations		18,114	18,114				589	589				833	833				915	915		
		39 - 100% to One Company	-		-			0		0												
		58 - Total Assets																	280	280		
		60 - AEPSC Bill less Indir and Int		55	55				(14)	(14)				7	7				98	98		
		64 - Member/Peak Load												6	6				6	6		
	5691 - Maint of Computer Hardware Total		-	19,165	19,165	-	19,165	0	589	589	-	589		1,650	1,650	-	1,650		2,236	2,236	-	2,236
	5692 - Maint of Computer Software	08 - Number of Electric Retail Cust		6,368	6,368				3,890	3,890				3,001	3,001				2,565	2,565		
		09 - Number of Employees		1,936	1,936				25	25				45	45				40	40		
		26 - Number of Stores Transactions												0	0				0	0		
		28 - Number of Trans Pole Miles		35,331	35,331				46,828	46,828				56,096	56,096				49,759	49,759		
		33 - Number of Workstations		148,359	148,359				4,383	4,383				7,950	7,950				7,138	7,138		
		39 - 100% to One Company	1,392		1,392			1,405		1,405			68		68			17		17		
		46 - Level of Const-Transmission		1,402	1,402				909	909				271	271				90	90		
		58 - Total Assets		40	40				41	41				5,940	5,940				17,824	17,824		
		60 - AEPSC Bill less Indir and Int							30	30				(28)	(28)				(63)	(63)		
		63 - Total Gross Utility Plant		221	221									715	715				751	751		
	5692 - Maint of Computer Software Total		1,392	193,657	195,049	-	195,049	1,405	56,105	57,510	-	57,510	68	73,990	74,058	-	74,058	17	78,104	78,121	-	78,121
	5693 - Maint of Communication Equip	28 - Number of Trans Pole Miles		8	8				(8)	(8)				26	26				8	8		
		33 - Number of Workstations		8,156	8,156				396	396				603	603				655	655		
		39 - 100% to One Company						-		-												
	5693 - Maint of Communication Equip Total			8,164	8,164	-	8,164	-	389	389	-	389		629	629	-	629		664	664	-	664
	5700 - Maint of Station Equipment	08 - Number of Electric Retail Cust		146	146				114	114				20	20				16	16		
		09 - Number of Employees		2,063	2,063				101	101				74	74				68	68		
		17 - Number of Purchase Orders		13	13				35	35									6	6		
		28 - Number of Trans Pole Miles		48,384	48,384				31,011	31,011				34,416	34,416				29,913	29,913		
		39 - 100% to One Company	184,877		184,877			284,497		284,497			320,291		320,291			344,315		344,315		
		58 - Total Assets		1,261	1,261				69,943	69,943				89,821	89,821				110,039	110,039		
		60 - AEPSC Bill less Indir and Int		(0)	(0)				6	6				(6)	(6)				25	25		
		63 - Total Gross Utility Plant												183	183				183	183		
	5700 - Maint of Station Equipment Total		184,877	51,867	236,744	-	236,744	284,497	101,211	385,707	-	385,707	320,291	124,509	444,800	-	444,800	344,315	140,249	484,564	-	484,564
	5701 - Maintenance of Energy Storage Equipment	28 - Number of Trans Pole Miles		-	-																	
	5701 - Maintenance of Energy Storage Equipment Total			-	-	-	-				-	-				-	-				-	-
	5710 - Maintenance of Overhead Lines	08 - Number of Electric Retail Cust		194	194				(161)	(161)				188	188				183	183		
		09 - Number of Employees		132	132				2	2												
		28 - Number of Trans Pole Miles		25,809	25,809				19,994	19,994				14,809	14,809				16,086	16,086		
		33 - Number of Workstations							15	15				(15)	(15)				(15)	(15)		
		39 - 100% to One Company	9,908		9,908			641,395		641,395			681,912		681,912			707,482		707,482		
		44 - Level of Const-Distribution		22	22				82	82				57	57				57	57		
		48 - MW Generating Capability												1	1				2	2		
		58 - Total Assets		40	40				915	915				5,764	5,764				5,780	5,780		
		60 - AEPSC Bill less Indir and Int		37	37				4	4				16	16				(5)	(5)		
		61 - Total Fixed Assets		101	101				841	841												
	5710 - Maintenance of Overhead Lines Total		9,908	26,335	36,243	-	36,243	641,395	21,692	663,087	-	663,087	681,912	20,819	702,731	-	702,731	707,482	22,088	729,570	-	729,570
	5720 - Maint of Underground Lines	28 - Number of Trans Pole Miles		81	81				206	206				42	42				127	127		
		39 - 100% to One Company						-		-								0		0		

Kentucky Power Company
AEPSC Chages by FERC Account, Allocation Factor and Allocation Type, net of share billed to Co-Owner
For 2014,2015,2016 and Test Year Ended February 2017

American Electric Power Service Corporation (AEPSC) is a wholly owned subsidiary of AEP and is the Centralized Service Company for the AEP System. AEPSC's activities are authorized by the FERC under the Public Utilities Holding Company Act of 2005. AEPSC performs, at cost, various corporate support services for subsidiaries of AEP, including Kentucky Power.

AEPSC transactions are accounted for through a work order system as required by the FERC. Costs for support services are accumulated in work orders and are billed to the company or companies benefiting from the service. Accounting within each work order is in accordance with the FERC Uniform System of Accounts. The costs for services benefiting only one company are directly assigned and are billed 100% to that company. Where services benefit more than one company, the costs for those services are allocated to the benefiting companies using an approved allocation factor. The allocation factor for any given allocation of costs is selected for use because it best reflects the cost driver associated with the service provided.

The FERC monitors the factors used for allocations, through required annual reporting, and can audit the validity of each factor. All services are billed at cost, with no profit charged, as required by the FERC's "at cost" rules.

			2014					2015					2016					TEST YEAR				
Account Type	FERC Account	Allocation Factor	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net
		58 - Total Assets																	43	43		
	5720 - Maint of Underground Lines Total			81	81	-	81	-	206	206	-	206		42	42	-	42	0	171	171	-	171
	5730 - Maint of Misc Trnsmssion Plt	09 - Number of Employees							0	0				1,555	1,555				57	57		
		28 - Number of Trans Pole Miles		24,711	24,711				75,198	75,198				23,326	23,326				23,875	23,875		
		39 - 100% to One Company	44,392		44,392			1,016		1,016			13,931		13,931			17,378		17,378		
		48 - MW Generating Capability												-	-				(1)	(1)		
		58 - Total Assets		82	82				210,626	210,626				241,383	241,383				297,621	297,621		
		60 - AEPSC Bill less Indir and Int												-	-				-	-		
	5730 - Maint of Misc Trnsmssion Plt Total		44,392	24,793	69,186	-	69,186	1,016	285,825	286,841	-	286,841	13,931	266,264	280,195	-	280,195	17,378	321,552	338,931	-	338,931
	5757 - Market facilitation, monitoring and compliance services	28 - Number of Trans Pole Miles		(0)	(0)																	
	5757 - Market facilitation, monitoring and compliance services Total			(0)	(0)	-	(0)				-	-				-	-				-	-
	5800 - Oper Supervision & Engineering	05 - Number of CIS Customers Mail												2	2				2	2		
		08 - Number of Electric Retail Cust		164,076	164,076				135,069	135,069				160,803	160,803				168,315	168,315		
		09 - Number of Employees		16,215	16,215				16,277	16,277				19,828	19,828				18,027	18,027		
		17 - Number of Purchase Orders		11	11				111	111				32	32				49	49		
		26 - Number of Stores Transactions		14	14																	
		27 - Number of Telephones		55	55				63	63				61	61				60	60		
		28 - Number of Trans Pole Miles		1,005	1,005				1,836	1,836				2,505	2,505				1,880	1,880		
		33 - Number of Workstations		11,420	11,420				12,489	12,489				6,897	6,897				5,197	5,197		
		39 - 100% to One Company	109,413		109,413			93,218		93,218			139,186		139,186			156,337		156,337		
		44 - Level of Const-Distribution		4,226	4,226				412	412				675	675				1,311	1,311		
		48 - MW Generating Capability		4,246	4,246				1,171	1,171				2,043	2,043				1,814	1,814		
		58 - Total Assets		15,186	15,186				16,458	16,458				14,307	14,307				15,094	15,094		
		60 - AEPSC Bill less Indir and Int		(698)	(698)				1	1				388	388				854	854		
		61 - Total Fixed Assets		13,333	13,333				12,169	12,169				21,183	21,183				32,660	32,660		
		63 - Total Gross Utility Plant		34	34				4,400	4,400				11,113	11,113				10,173	10,173		
		70 - No Nonelectric OAR Invoices												(2)	(2)				(2)	(2)		
	5800 - Oper Supervision & Engineering Total		109,413	229,122	338,535	-	338,535	93,218	200,458	293,675	-	293,675	139,186	239,836	379,022	-	379,022	156,337	255,435	411,772	-	411,772
	5810 - Load Dispatching	08 - Number of Electric Retail Cust		1,563	1,563				2,009	2,009				1,414	1,414				1,210	1,210		
		28 - Number of Trans Pole Miles		301	301				(32)	(32)				11	11				(596)	(596)		
		33 - Number of Workstations		1,233	1,233				1,567	1,567				1,709	1,709				1,585	1,585		
		39 - 100% to One Company						-		-												
	5810 - Load Dispatching Total			3,098	3,098	-	3,098	-	3,544	3,544	-	3,544		3,134	3,134	-	3,134		2,200	2,200	-	2,200
	5820 - Station Expenses	28 - Number of Trans Pole Miles		628	628				310	310				321	321				904	904		
		39 - 100% to One Company	1,902		1,902			165,246		165,246			135,483		135,483			143,261		143,261		
		46 - Level of Const-Transmission		672	672				1,025	1,025				1,801	1,801				2,280	2,280		
	5820 - Station Expenses Total		1,902	1,299	3,201	-	3,201	165,246	1,335	166,581	-	166,581	135,483	2,122	137,605	-	137,605	143,261	3,184	146,445	-	146,445
	5830 - Overhead Line Expenses	08 - Number of Electric Retail Cust		-	-				-	-				7	7				6	6		
		28 - Number of Trans Pole Miles		9	9				8	8				21	21				82	82		
		39 - 100% to One Company						1,136		1,136			438		438			438		438		
		48 - MW Generating Capability							(0)	(0)												
		60 - AEPSC Bill less Indir and Int		1	1				(1)	(1)				(0)	(0)				(0)	(0)		
	5830 - Overhead Line Expenses Total			9	9	-	9	1,136	8	1,144	-	1,144	438	28	467	-	467	438	88	526	-	526
	5840 - Underground Line Expenses	08 - Number of Electric Retail Cust		5,624	5,624				4,799	4,799				5,446	5,446				5,468	5,468		
		39 - 100% to One Company						-		-												
		58 - Total Assets		107	107																	
	5840 - Underground Line Expenses Total			5,731	5,731	-	5,731	-	4,799	4,799	-	4,799		5,446	5,446	-	5,446		5,468	5,468	-	5,468
	5841 - Operation of Energy Storage Equipment	28 - Number of Trans Pole Miles		0	0																	
	5841 - Operation of Energy Storage Equipment Total			0	0	-	0				-	-				-	-				-	-
	5860 - Meter Expenses	05 - Number of CIS Customers Mail		12	12																	
		08 - Number of Electric Retail Cust		66,158	66,158				48,436	48,436				56,433	56,433				56,617	56,617		
		09 - Number of Employees		7,901	7,901				5,726	5,726				9,820	9,820				10,015	10,015		
		17 - Number of Purchase Orders							0	0												
		26 - Number of Stores Transactions		840	840				206	206				384	384				132	132		
		27 - Number of Telephones												2	2							
		28 - Number of Trans Pole Miles		423	423				398	398				636	636				688	688		
		33 - Number of Workstations		800	800				532	532				275	275				133	133		
		39 - 100% to One Company	55,465		55,465			40,064		40,064			15,360		15,360			15,393		15,393		
		44 - Level of Const-Distribution							1	1												
		58 - Total Assets		2,946	2,946				2,640	2,640				2,199	2,199				2,212	2,212		
		60 - AEPSC Bill less Indir and Int		32	32				(37)	(37)				(8)	(8)				45	45		
		61 - Total Fixed Assets																	164	164		
		63 - Total Gross Utility Plant							16	16												
	5860 - Meter Expenses Total		55,465	79,111	134,576	-	134,576	40,064	57,918	97,982	-	97,982	15,360	69,742	85,102	-	85,102	15,393	70,006	85,399	-	85,399
	5870 - Customer Installations Exp	58 - Total Assets							240	240												
	5870 - Customer Installations Exp Total					-	-		240	240	-	240				-	-				-	-
	5880 - Miscellaneous Distribution Exp	06 - Number of Commercial Customers		1	1																	
		08 - Number of Electric Retail Cust		153,143	153,143				133,298	133,298				150,361	150,361				153,299	153,299		
		09 - Number of Employees		42,650	42,650				54,367	54,367				47,003	47,003				47,998	47,998		
		15 - Number of Non UMWA Employees		3	3																	
		16 - Number of Phone Center Calls		8,245	8,245				9,856	9,856				6,925	6,925				6,787	6,787		
		17 - Number of Purchase Orders		522	522				529	529				633	633				660	660		
		26 - Number of Stores Transactions							0	0												
		27 - Number of Telephones		5,674	5,674				27,159	27,159				52,423	52,423				52,036	52,036		
		28 - Number of Trans Pole Miles		9,638	9,638				10,968	10,968				5,329	5,329				4,168	4,168		
		31 - Number of Vehicles		278	278				437	437				448	448				494	494		
		32 - Number of Vendor Invoice Pay		619	619				549	549				(866)	(866)				427	427		
		33 - Number of Workstations		7,219	7,219				6,060	6,060				5,041	5,041				4,753	4,753		
		39 - 100% to One Company	12,136		12,136			155,500		155,500			198,167		198,167			182,664		182,664		
		39 - 100% to One Company	128,182		128,182			13,166		13,166			43,442		43,442			(61,583)		(61,583)		
		44 - Level of Const-Distribution		43	43				1	1				65	65				51	51		
		46 - Level of Const-Transmission							11	11												
		48 - MW Generating Capability		906	906				(906)	(906)				353	353				680	680		
		58 - Total Assets		102,452	102,452				104,700	104,700				98,894	98,894				106,023	106,023		
		60 - AEPSC Bill less Indir and Int		(265)	(265)				74	74				163	163				1	1		
		61 - Total Fixed Assets		874	874				939	939				1,816	1,816				2,309	2,309		
		63 - Total Gross Utility Plant		786	786				160	160				310	310				310	310		
	5880 - Miscellaneous Distribution Exp Total		140,318	332,788	473,106	-	473,106	168,666	348,204	516,870	-	516,870	241,609	368,898	610,507	-	610,507	121,081	379,997	501,078	-	501,078
	5890 - Rents	08 - Number of Electric Retail Cust		-	-									-	-				-	-		
		39 - 100% to One Company	360		360								230		230			230		230		
	5890 - Rents Total		360	-	360	-	360				-	-	230	-	230	-	230	230	-	230	-	230
	5900 - Maint Supv & Engineering	08 - Number of Electric Retail Cust		785	785				287	287				2,219	2,219				2,379	2,379		
		09 - Number of Employees		859	859				394	394				155	155				155	155		
		28 - Number of Trans Pole Miles		27	27				(21)	(21)				4	4				(37)	(37)		
		39 - 100% to One Company						-		-								1,190		1,190		
		60 - AEPSC Bill less Indir and Int		(22)	(22)																	
	5900 - Maint Supv & Engineering Total			1,648	1,648	-	1,648	-	659	659	-	659		2,378	2,378	-	2,378	1,190	2,497	3,687	-	3,687
	5910 - Maintenance of Structures	28 - Number of Trans Pole Miles		(17)	(17)				(7)	(7)				15	15				(5)	(5)		
		33 - Number of Workstations		2,694	2,694				1,802	1,802				3,316	3,316				3,080	3,080		
		39 - 100% to One Company						1,764		1,764			2,060		2,060			2,668		2,668		
	5910 - Maintenance of Structures Total			2,677	2,677	-	2,677	1,764	1,795	3,558	-	3,558	2,060	3,331	5,391	-	5,391	2,668	3,075	5,743	-	5,743
	5920 - Maint of Station Equipment	28 - Number of Trans Pole Miles		1,935	1,935				1,165	1,165				1,701	1,701				1,221	1,221		
		39 - 100% to One Company	130,159		130,159			377,384		377,384			264,846		264,846			237,177		237,177		
		46 - Level of Const-Transmission		55,270	55,270				65,144	65,144				26,142	26,142				25,688	25,688		
		58 - Total Assets		123	123				2	2									138	138		
		60 - AEPSC Bill less Indir and Int		28	28				80	80				(40)	(40)				(13)	(13)		
		63 - Total Gross Utility Plant												70	70				70	70		
	5920 - Maint of Station Equipment Total		130,159	57,356	187,515	-	187,515	377,384	66,390	443,774	-	443,774	264,846	27,872	292,718	-	292,718	237,177	27,104	264,281	-	264,281
	5922 - Maintenance of Energy Storage Equipment	28 - Number of Trans Pole Miles		(0)	(0)				-	-				0	0				0	0		
	5922 - Maintenance of Energy Storage Equipment Total			(0)	(0)	-	(0)		-	-	-	-		0	0	-	0		0	0	-	0
	5930 - Maintenance of Overhead Lines	08 - Number of Electric Retail Cust		19,446	19,446				19,541	19,541				26,045	26,045				25,575	25,575		
		09 - Number of Employees							13	13												

Kentucky Power Company
AEPSC Chages by FERC Account, Allocation Factor and Allocation Type, net of share billed to Co-Owner
For 2014,2015,2016 and Test Year Ended February 2017

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The FERC monitors the factors used for allocations, through required annual reporting, and can audit the validity of each factor. All services are billed at cost, with no profit charged, as required by the FERC's "at cost" rules.

Account Type	FERC Account	Allocation Factor	2014 Direct	2014 Allocated	2014 AEPSC Billed to Kentucky Power	2014 Share Billed to Co-Owner	2014 AEPSC Billed to Kentucky Power, Net	2015 Direct	2015 Allocated	2015 AEPSC Billed to Kentucky Power	2015 Share Billed to Co-Owner	2015 AEPSC Billed to Kentucky Power, Net	2016 Direct	2016 Allocated	2016 AEPSC Billed to Kentucky Power	2016 Share Billed to Co-Owner	2016 AEPSC Billed to Kentucky Power, Net	TEST YEAR Direct	TEST YEAR Allocated	TEST YEAR AEPSC Billed to Kentucky Power	TEST YEAR Share Billed to Co-Owner	TEST YEAR AEPSC Billed to Kentucky Power, Net
		28 - Number of Trans Pole Miles		(51)	(51)				156	156				(156)	(156)				(299)	(299)		
		39 - 100% to One Company	11,261		11,261			30,545		30,545			4,643		4,643			1,524		1,524		
		48 - MW Generating Capability		-	-																	
		58 - Total Assets		53	53				51	51				160	160				151	151		
		60 - AEPSC Bill less Indir and Int		(79)	(79)				20	20				(21)	(21)				(39)	(39)		
	5930 - Maintenance of Overhead Lines Total		11,261	19,369	30,630	-	30,630	30,545	19,781	50,326	-	50,326	4,643	26,028	30,671	-	30,671	1,524	25,387	26,911	-	26,911
	5940 - Maint of Underground Lines	08 - Number of Electric Retail Cust		(0)	(0)				-	-				0	0				0	0		
		28 - Number of Trans Pole Miles		0	0				0	0				0	0				1	1		
		48 - MW Generating Capability							0	0												
		60 - AEPSC Bill less Indir and Int		0	0				(0)	(0)				-	-				-	-		
	5940 - Maint of Underground Lines Total			0	0	-	0		(0)	(0)	-	(0)		0	0	-	0		1	1	-	1
	5950 - Maint of Lne Trnf,Rglators&Dvi	08 - Number of Electric Retail Cust		47	47				(36)	(36)				19	19				(60)	(60)		
		09 - Number of Employees												27	27				27	27		
	5950 - Maint of Lne Trnf,Rglators&Dvi Total			47	47	-	47		(36)	(36)	-	(36)		45	45	-	45		(34)	(34)	-	(34)
	5960 - Maint of Strt Lghtng & Sgnal S	28 - Number of Trans Pole Miles		0	0				0	0				(0)	(0)				(0)	(0)		
		39 - 100% to One Company						12		12												
		60 - AEPSC Bill less Indir and Int												-	-				-	-		
	5960 - Maint of Strt Lghtng & Sgnal S Total			0	0	-	0	12	0	12	-	12		(0)	(0)	-	(0)		(0)	(0)	-	(0)
	5970 - Maintenance of Meters	08 - Number of Electric Retail Cust		220	220				120	120				149	149				143	143		
		26 - Number of Stores Transactions		399	399																	
		28 - Number of Trans Pole Miles		51	51				(5)	(5)				29	29				(106)	(106)		
		39 - 100% to One Company	2,754		2,754			26,684		26,684			2,328		2,328			2,188		2,188		
	5970 - Maintenance of Meters Total		2,754	670	3,424	-	3,424	26,684	115	26,799	-	26,799	2,328	178	2,506	-	2,506	2,188	36	2,224	-	2,224
	5980 - Maint of Misc Distribution Plt	28 - Number of Trans Pole Miles		849	849				625	625				505	505				614	614		
		39 - 100% to One Company	1,414		1,414			0		0			3,349		3,349			3,122		3,122		
		58 - Total Assets																	91	91		
		60 - AEPSC Bill less Indir and Int												-	-				-	-		
	5980 - Maint of Misc Distribution Plt Total		1,414	849	2,262	-	2,262	0	625	625	-	625	3,349	505	3,854	-	3,854	3,122	705	3,828	-	3,828
	9010 - Supervision - Customer Accts	05 - Number of CIS Customers Mail		3,717	3,717				3,019	3,019				4,429	4,429				5,159	5,159		
		08 - Number of Electric Retail Cust		12,111	12,111				12,617	12,617				24,230	24,230				26,155	26,155		
		09 - Number of Employees		980	980				571	571				3,338	3,338				3,290	3,290		
		11 - Number of GL Transactions		1	1																	
		39 - 100% to One Company						-		-												
		58 - Total Assets		2	2									185	185				185	185		
		60 - AEPSC Bill less Indir and Int		38	38				(38)	(38)												
		63 - Total Gross Utility Plant		72	72									95	95				95	95		
	9010 - Supervision - Customer Accts Total			16,921	16,921	-	16,921	-	16,169	16,169	-	16,169		32,276	32,276	-	32,276		34,884	34,884	-	34,884
	9020 - Meter Reading Expenses	05 - Number of CIS Customers Mail		21,423	21,423				2,400	2,400				182	182				18	18		
		08 - Number of Electric Retail Cust		37,908	37,908				49,940	49,940				52,506	52,506				50,949	50,949		
		09 - Number of Employees		1,464	1,464				498	498				1,069	1,069				1,087	1,087		
		16 - Number of Phone Center Calls												353	353				353	353		
		28 - Number of Trans Pole Miles							10	10				(10)	(10)				(24)	(24)		
		33 - Number of Workstations		54	54				14	14				7	7				7	7		
		39 - 100% to One Company	(11,223)		(11,223)			-		-												
		58 - Total Assets		655	655				1,553	1,553				2,011	2,011				1,419	1,419		
	9020 - Meter Reading Expenses Total		(11,223)	61,503	50,280	-	50,280	-	54,415	54,415	-	54,415		56,118	56,118	-	56,118		53,809	53,809	-	53,809
	9030 - Cust Records & Collection Exp	05 - Number of CIS Customers Mail		245,710	245,710				210,405	210,405				190,408	190,408				196,948	196,948		
		08 - Number of Electric Retail Cust		796,909	796,909				832,944	832,944				823,528	823,528				832,279	832,279		
		09 - Number of Employees		75,794	75,794				83,672	83,672				90,851	90,851				90,215	90,215		
		11 - Number of GL Transactions												0	0				0	0		
		12 - Number of Help Desk Calls		1,732	1,732																	
		15 - Number of Non UMWA Employees		9	9																	
		16 - Number of Phone Center Calls		884,704	884,704				786,510	786,510				837,151	837,151				857,861	857,861		
		17 - Number of Purchase Orders		259	259				210	210				316	316				244	244		
		20 - Number of Remittance Items		160,794	160,794				135,120	135,120				141,106	141,106				142,075	142,075		
		33 - Number of Workstations		1,278	1,278				3,910	3,910				4,717	4,717				4,794	4,794		
		39 - 100% to One Company	1,164,769		1,164,769			1,095,284		1,095,284			1,068,974		1,068,974			1,081,480		1,081,480		
		48 - MW Generating Capability		67	67				(34)	(34)				(10)	(10)				(126)	(126)		
		58 - Total Assets		19,569	19,569				16,187	16,187				15,479	15,479				22,798	22,798		
		60 - AEPSC Bill less Indir and Int		423	423				350	350				472	472				(212)	(212)		
		63 - Total Gross Utility Plant		140	140																	
		70 - No Nonelectric OAR Invoices		14,804	14,804				15,146	15,146				13,687	13,687				13,879	13,879		
	9030 - Cust Records & Collection Exp Total		1,164,769	2,202,194	3,366,963	-	3,366,963	1,095,284	2,084,421	3,179,705	-	3,179,705	1,068,974	2,117,706	3,186,680	-	3,186,680	1,081,480	2,160,756	3,242,235	-	3,242,235
	9040 - Uncollectible Accounts	26 - Number of Stores Transactions												3	3				3	3		
	9040 - Uncollectible Accounts Total					-	-				-	-		3	3	-	3		3	3	-	3
	9050 - Misc Customer Accounts Exp	05 - Number of CIS Customers Mail		29	29									4	4				4	4		
		08 - Number of Electric Retail Cust		2,495	2,495				1,539	1,539				662	662				618	618		
		09 - Number of Employees		13	13																	
		12 - Number of Help Desk Calls		7,639	7,639																	
		20 - Number of Remittance Items		44	44				195	195				9	9				25	25		
		33 - Number of Workstations		3,265	3,265				10,274	10,274				9,638	9,638				9,839	9,839		
		39 - 100% to One Company	3,722		3,722			-		-												
		58 - Total Assets		341	341				334	334				495	495				509	509		
		60 - AEPSC Bill less Indir and Int							-	-												
	9050 - Misc Customer Accounts Exp Total		3,722	13,825	17,547	-	17,547	-	12,342	12,342	-	12,342		10,807	10,807	-	10,807		10,995	10,995	-	10,995
	9070 - Supervision - Customer Service	08 - Number of Electric Retail Cust		49,864	49,864				42,718	42,718				33,782	33,782				35,036	35,036		
		09 - Number of Employees		2,780	2,780				3,335	3,335				5,110	5,110				4,632	4,632		
		16 - Number of Phone Center Calls		809	809				762	762				12	12				12	12		
		17 - Number of Purchase Orders												2	2				2	2		
		31 - Number of Vehicles							1	1												
		32 - Number of Vendor Invoice Pay		21	21																	
		39 - 100% to One Company	29,983		29,983			26,620		26,620			6,478		6,478			7,148		7,148		
		58 - Total Assets		2,153	2,153				2,204	2,204				1,471	1,471				1,329	1,329		
		60 - AEPSC Bill less Indir and Int		(19)	(19)				2	2				2	2				19	19		
	9070 - Supervision - Customer Service Total		29,983	55,607	85,590	-	85,590	26,620	49,021	75,641	-	75,641	6,478	40,378	46,856	-	46,856	7,148	41,031	48,179	-	48,179
	9080 - Customer Assistance Expenses	08 - Number of Electric Retail Cust		13,708	13,708				12,132	12,132				12,155	12,155				12,505	12,505		
		09 - Number of Employees		48	48				1,121	1,121				295	295				242	242		
		16 - Number of Phone Center Calls		2,460	2,460				2,905	2,905				2,858	2,858				2,773	2,773		
		32 - Number of Vendor Invoice Pay		55	55				107	107				135	135				143	143		
		39 - 100% to One Company	1,735		1,735			259		259			630		630			279		279		
		58 - Total Assets		1,502	1,502				1,074	1,074				1,456	1,456				1,551	1,551		
		60 - AEPSC Bill less Indir and Int		(25)	(25)				26	26				84	84				58	58		
	9080 - Customer Assistance Expenses Total		1,735	17,748	19,483	-	19,483	259	17,365	17,625	-	17,625	630	16,982	17,612	-	17,612	279	17,272	17,551	-	17,551
	9100 - Misc Cust Svc&Informational Ex	08 - Number of Electric Retail Cust		8	8				6	6				924	924				1,523	1,523		
		09 - Number of Employees		713	713				1,333	1,333				898	898				499	499		
		31 - Number of Vehicles												63	63				63	63		
		33 - Number of Workstations		162	162									2	2				2	2		
		39 - 100% to One Company	12,102		12,102			36,816		36,816												
		39 - 100% to One Company						129		129												
		58 - Total Assets							104	104				41	41				14	14		
		60 - AEPSC Bill less Indir and Int		32	32				293	293				174	174				(22)	(22)		
	9100 - Misc Cust Svc&Informational Ex Total		12,102	915	13,017	-	13,017	36,945	1,737	38,682	-	38,682		2,103	2,103	-	2,103		2,079	2,079	-	2,079
	9110 - Supervision - Sales Expenses	08 - Number of Electric Retail Cust												-	-				11	11		
		09 - Number of Employees							0	0												
	9110 - Supervision - Sales Expenses Total					-	-		0	0	-	0		-	-	-	-		11	11	-	11
	9120 - Demonstrating & Selling Exp	06 - Number of Commercial Customers		1,312	1,312				5,052	5,052				2,954	2,954				3,724	3,724		
		08 - Number of Electric Retail Cust		48,279	48,279				38,105	38,105				33,977	33,977				35,524	35,524		
		09 - Number of Employees												14	14				14	14		
		33 - Number of Workstations							1	1												
		44 - Level of Const-Distribution							0	0												
		58 - Total Assets		536	536				546	546				95	95				29	29		
	9120 - Demonstrating & Selling Exp Total			50,127	50,127	-	50,127		43,706	43,706	-	43,706		37,040	37,040	-	37,040		39,291	39,291	-	39,291

Kentucky Power Company
AEPSC Chages by FERC Account, Allocation Factor and Allocation Type, net of share billed to Co-Owner
For 2014,2015,2016 and Test Year Ended February 2017

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			2014					2015					2016					TEST YEAR				
Account Type	FERC Account	Allocation Factor	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net
	9130 - Advertising Expenses	09 - Number of Employees												344	344				344	344		
		48 - MW Generating Capability												-	-				-	-		
		58 - Total Assets												43	43				43	43		
	9130 - Advertising Expenses Total					-	-				-	-		387	387	-	387		387	387	-	387
	9200 - Administrative & Gen Salaries	05 - Number of CIS Customers Mail		6,755	6,755				2,783	2,783				2,631	2,631				3,012	3,012		
		06 - Number of Commercial Customers		31,831	31,831				21,688	21,688				16,896	16,896				15,327	15,327		
		08 - Number of Electric Retail Cust		284,114	284,114				241,343	241,343				271,555	271,555				290,225	290,225		
		09 - Number of Employees		1,614,152	1,614,152				1,380,090	1,380,090				1,281,914	1,281,914				1,300,505	1,300,505		
		11 - Number of GL Transactions		163,286	163,286				160,093	160,093				177,533	177,533				184,312	184,312		
		12 - Number of Help Desk Calls		2,462	2,462																	
		15 - Number of Non UMWA Employees		4,595	4,595																	
		16 - Number of Phone Center Calls		1,131	1,131				1,186	1,186				1,295	1,295				1,460	1,460		
		17 - Number of Purchase Orders		92,654	92,654				51,838	51,838				33,864	33,864				30,362	30,362		
		26 - Number of Stores Transactions		78,337	78,337				56,523	56,523				49,695	49,695				47,720	47,720		
		27 - Number of Telephones		68	68									160	160				170	170		
		28 - Number of Trans Pole Miles		157,760	157,760				196,769	196,769				247,379	247,379				227,357	227,357		
		30 - Number of Travel Transactions		27	27																	
		31 - Number of Vehicles		162	162									892	892				892	892		
		32 - Number of Vendor Invoice Pay		82,036	82,036				84,287	84,287				70,544	70,544				69,859	69,859		
		33 - Number of Workstations		208,397	208,397				216,933	216,933				132,585	132,585				134,723	134,723		
		37 - AEPSC Past 3 Months Total Bill		18	18				(327)	(327)												
		39 - 100% to One Company	2,131,448		2,131,448			1,603,144		1,603,144			1,359,652		1,359,652			1,320,812		1,320,812		
		39 - 100% to One Company						268,601		268,601			432,660		432,660			432,660		432,660		
		40 - Equal Share Ratio		46,041	46,041				47,162	47,162				22,054	22,054				17,019	17,019		
		43 - KWH Sales		599	599																	
		44 - Level of Const-Distribution		2,812	2,812				741	741				630	630				837	837		
		46 - Level of Const-Transmission		1,060	1,060				524	524				393	393				311	311		
		48 - MW Generating Capability		438,041	438,041				301,029	301,029				318,555	318,555				330,535	330,535		
		49 - MWH's Generation		135,451	135,451				87,447	87,447				126,042	126,042				144,007	144,007		
		51 - Past 3 Mo MMBTU's Burned (Tot)		197,891	197,891				116,971	116,971				152,131	152,131				164,785	164,785		
		55 - Past 3 MMBTU Burned (Solid)		2,233	2,233				1,827	1,827				309	309				218	218		
		57 - Tons of Fuel Acquired		348	348				4,633	4,633				868	868				978	978		
		58 - Total Assets		3,839,035	3,839,035				3,648,583	3,648,583				4,742,993	4,742,993				4,844,903	4,844,903		
		60 - AEPSC Bill less Indir and Int		(4,676)	(4,676)				45,024	45,024				25,508	25,508				2,758	2,758		
		61 - Total Fixed Assets		392,602	392,602				298,700	298,700				442,113	442,113				453,347	453,347		
		63 - Total Gross Utility Plant		34,706	34,706				34,354	34,354				29,464	29,464				28,426	28,426		
		64 - Member/Peak Load		133,650	133,650				116,064	116,064				134,261	134,261				138,560	138,560		
		67 - Number of Banking Transactions		42,140	42,140				46,158	46,158				42,904	42,904				41,846	41,846		
		70 - No Nonelectric OAR Invoices		15,126	15,126				17,449	17,449				15,505	15,505				15,401	15,401		
	9200 - Administrative & Gen Salaries Total		2,131,448	8,004,844	10,136,292	(1,540,394)	8,595,898	1,871,745	7,179,872	9,051,617	(1,623,116)	7,428,500	1,792,312	8,340,674	10,132,985	(2,326,007)	7,806,978	1,753,472	8,489,855	10,243,327	(2,396,829)	7,846,498
	9210 - Office Supplies and Expenses	05 - Number of CIS Customers Mail		802	802				278	278				306	306				349	349		
		06 - Number of Commercial Customers		59	59				141	141				45	45				48	48		
		08 - Number of Electric Retail Cust		2,863	2,863				2,296	2,296				4,644	4,644				7,115	7,115		
		09 - Number of Employees		65,681	65,681				66,434	66,434				50,622	50,622				54,144	54,144		
		11 - Number of GL Transactions		1,238	1,238				1,354	1,354				2,052	2,052				1,938	1,938		
		12 - Number of Help Desk Calls		24	24																	
		15 - Number of Non UMWA Employees		101	101																	
		16 - Number of Phone Center Calls		487	487				196	196				332	332				353	353		
		17 - Number of Purchase Orders		3,316	3,316				4,266	4,266				1,237	1,237				1,570	1,570		
		21 - Number of Remote Terminal		288	288																	
		26 - Number of Stores Transactions		151	151				77	77				56	56				56	56		
		27 - Number of Telephones		66,948	66,948				77,266	77,266				66,263	66,263				63,086	63,086		
		28 - Number of Trans Pole Miles		9,516	9,516				5,863	5,863				8,624	8,624				9,074	9,074		
		30 - Number of Travel Transactions		0	0																	
		31 - Number of Vehicles		0	0									3	3				3	3		
		32 - Number of Vendor Invoice Pay		(77,324)	(77,324)				(61,350)	(61,350)				(68,432)	(68,432)				(81,942)	(81,942)		
		33 - Number of Workstations		92,718	92,718				86,964	86,964				17,222	17,222				11,881	11,881		
		39 - 100% to One Company	32,539		32,539			29,192		29,192			13,905		13,905			13,905		13,905		
		39 - 100% to One Company	15,564		15,564			4,365		4,365			9,500		9,500			47,200		47,200		
		40 - Equal Share Ratio		826	826				976	976				197	197				227	227		
		43 - KWH Sales		1	1																	
		44 - Level of Const-Distribution		2	2				1	1				1	1				1	1		
		46 - Level of Const-Transmission		16	16				4	4				11	11				12	12		
		48 - MW Generating Capability		54,917	54,917				15,934	15,934				10,863	10,863				10,581	10,581		
		49 - MWH's Generation		145	145				196	196				5,981	5,981				5,963	5,963		
		51 - Past 3 Mo MMBTU's Burned (Tot)		195	195				73	73				131	131				134	134		
		55 - Past 3 MMBTU Burned (Solid)		14	14				16	16				3	3				2	2		
		57 - Tons of Fuel Acquired		0	0				5	5				1	1				1	1		
		58 - Total Assets		321,917	321,917				354,103	354,103				414,745	414,745				407,613	407,613		
		60 - AEPSC Bill less Indir and Int		(14,002)	(14,002)				(5,720)	(5,720)				363	363				708	708		
		61 - Total Fixed Assets		4,730	4,730				3,700	3,700				3,342	3,342				3,309	3,309		
		63 - Total Gross Utility Plant		194	194				96	96				974	974				1,006	1,006		
		64 - Member/Peak Load		971	971				678	678				1,329	1,329				1,369	1,369		
		67 - Number of Banking Transactions		237	237				260	260				227	227				233	233		
		70 - No Nonelectric OAR Invoices		93	93				143	143				98	98				99	99		
	9210 - Office Supplies and Expenses Total		48,103	537,127	585,230	(86,408)	498,822	33,557	554,248	587,805	(103,112)	484,693	23,405	521,239	544,644	(130,479)	414,165	61,105	498,933	560,038	(135,004)	425,034
	9220 - Administrative Exp Trnsf - Cr	08 - Number of Electric Retail Cust		-	-																	
		09 - Number of Employees		-	-				-	-				0	0				(0)	(0)		
		28 - Number of Trans Pole Miles							-	-				-	-				-	-		
		33 - Number of Workstations												-	-				-	-		
		51 - Past 3 Mo MMBTU's Burned (Tot)		-	-																	
		60 - AEPSC Bill less Indir and Int		(0)	(0)				(0)	(0)				0	0				0	0		
		63 - Total Gross Utility Plant		-	-																	
	9220 - Administrative Exp Trnsf - Cr Total			(0)	(0)	-	(0)		(0)	(0)	-	(0)		0	0	-	0		0	0	-	0
	9230 - Outside Services Employed	08 - Number of Electric Retail Cust		67,226	67,226				95,057	95,057				48,981	48,981				68,358	68,358		
		09 - Number of Employees		132,408	132,408				135,638	135,638				144,934	144,934				136,325	136,325		
		11 - Number of GL Transactions		1,620	1,620				561	561				14,119	14,119				14,970	14,970		
		12 - Number of Help Desk Calls		47	47																	
		15 - Number of Non UMWA Employees		173	173																	
		16 - Number of Phone Center Calls		(82)	(82)				(80)	(80)				(153)	(153)				(162)	(162)		
		17 - Number of Purchase Orders		2,884	2,884				8,912	8,912				9,274	9,274				9,511	9,511		
		20 - Number of Remittance Items		11	11																	
		26 - Number of Stores Transactions		1,851	1,851				6,160	6,160				4,334	4,334				6,114	6,114		
		27 - Number of Telephones							0	0												
		28 - Number of Trans Pole Miles		22,157	22,157				25,121	25,121				61,959	61,959				58,842	58,842		
		31 - Number of Vehicles												420	420				420	420		
		32 - Number of Vendor Invoice Pay		12,537	12,537				17,925	17,925				15,772	15,772				15,658	15,658		
		33 - Number of Workstations		77,657	77,657				128,114	128,114				76,855	76,855				75,319	75,319		
		37 - AEPSC Past 3 Months Total Bill		501,257	501,257				331,087	331,087				261,173	261,173				(774,879)	(774,879)		
		39 - 100% to One Company	703		703			481,475		481,475												
		39 - 100% to One Company	198,921		198,921			43,927		43,927			275,769		275,769			273,916		273,916		
		40 - Equal Share Ratio		11,983	11,983				714	714				23	23				23	23		
		44 - Level of Const-Distribution		7	7				12	12												
		46 - Level of Const-Transmission		34	34				1,890	1,890				2,924	2,924				2,714	2,714		
		48 - MW Generating Capability		66,418	66,418				44,185	44,185				41,972	41,972				45,753	45,753		
		49 - MWH's Generation		3,720	3,720				1,747	1,747				19,300	19,300				20,643	20,643		
		51 - Past 3 Mo MMBTU's Burned (Tot)		5,698	5,698				4,258	4,258				1,846	1,846				2,348	2,348		
		57 - Tons of Fuel Acquired		303	303																	
		58 - Total Assets		487,504	487,504				467,649	467,649				648,778	648,778				614,566	614,566		
		60 - AEPSC Bill less Indir and Int		163	163				90	90				389	389				(14,415)	(14,415)		
		61 - Total Fixed Assets		15,910	15,910				15,053	15,053				17,090	17,090				15,203	15,203		
		63 - Total Gross Utility Plant		45,506	45,506				5,837	5,837				77,193	77,193				79,637	79,637		

Kentucky Power Company
AEPSC Chages by FERC Account, Allocation Factor and Allocation Type, net of share billed to Co-Owner
For 2014,2015,2016 and Test Year Ended February 2017

American Electric Power Service Corporation (AEPSC) is a wholly owned subsidiary of AEP and is the Centralized Service Company for the AEP System. AEPSC's activities are authorized by the FERC under the Public Utilities Holding Company Act of 2005. AEPSC performs, at cost, various corporate support services for subsidiaries of AEP, including Kentucky Power.

AEPSC transactions are accounted for through a work order system as required by the FERC. Costs for support services are accumulated in work orders and are billed to the company or companies benefiting from the service. Accounting within each work order is in accordance with the FERC Uniform System of Accounts. The costs for services benefiting only one company are directly assigned and are billed 100% to that company. Where services benefit more than one company, the costs for those services are allocated to the benefiting companies using an approved allocation factor. The allocation factor for any given allocation of costs is selected for use because it best reflects the cost driver associated with the service provided.

The FERC monitors the factors used for allocations, through required annual reporting, and can audit the validity of each factor. All services are billed at cost, with no profit charged, as required by the FERC's "at cost" rules.

			2014					2015					2016					TEST YEAR				
Account Type	FERC Account	Allocation Factor	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net
		64 - Member/Peak Load		1,820	1,820				723	723				8,602	8,602				7,431	7,431		
		67 - Number of Banking Transactions		919	919				1,134	1,134				645	645				607	607		
		70 - No Nonelectric OAR Invoices		559	559				357	357				987	987				983	983		
	9230 - Outside Services Employed Total		199,624	1,460,289	1,659,913	(221,736)	1,438,177	525,403	1,292,143	1,817,546	(304,376)	1,513,170	275,769	1,457,416	1,733,185	(370,649)	1,362,536	273,916	385,968	659,885	(120,665)	539,220
	9250 - Injuries and Damages	08 - Number of Electric Retail Cust		-	-																	
		09 - Number of Employees		6,829	6,829				5,795	5,795				10,651	10,651				10,755	10,755		
		28 - Number of Trans Pole Miles		207	207									0	0				0	0		
		39 - 100% to One Company	3		3			-		-												
		58 - Total Assets												142	142				142	142		
		60 - AEPSC Bill less Indir and Int		49	49				9	9				9	9				143	143		
		61 - Total Fixed Assets												25	25				12	12		
	9250 - Injuries and Damages Total		3	7,085	7,088	(1,122)	5,966	-	5,805	5,805	(1,242)	4,562		10,827	10,827	(2,472)	8,355		11,052	11,052	(2,524)	8,527
	9260 - Employee Pensions & Benefits	08 - Number of Electric Retail Cust		108	108				175	175				237	237				237	237		
		09 - Number of Employees		3,547	3,547				3,264	3,264				7,434	7,434				9,068	9,068		
		17 - Number of Purchase Orders		25	25				28	28				5	5				5	5		
		20 - Number of Remittance Items							21	21				11	11				11	11		
		28 - Number of Trans Pole Miles		26	26				257	257				1,081	1,081				974	974		
		31 - Number of Vehicles		9	9																	
		32 - Number of Vendor Invoice Pay		1	1																	
		33 - Number of Workstations		-	-									23	23				23	23		
		39 - 100% to One Company						0		0			(8,945)		(8,945)			0		0		
		48 - MW Generating Capability		147	147				97	97				85	85				169	169		
		49 - MWH's Generation												14	14				14	14		
		58 - Total Assets		33,963	33,963				28,102	28,102				25,494	25,494				25,711	25,711		
		60 - AEPSC Bill less Indir and Int		296	296				(207)	(207)				166	166				299	299		
		61 - Total Fixed Assets		2	2				9	9												
		63 - Total Gross Utility Plant												344	344				344	344		
		64 - Member/Peak Load		23	23				66	66				(4)	(4)							
		67 - Number of Banking Transactions		22	22																	
	9260 - Employee Pensions & Benefits Total			38,169	38,169	(5,628)	32,541	0	31,811	31,811	(5,985)	25,826	(8,945)	34,890	25,945	(8,664)	17,281	0	36,855	36,855	(9,159)	27,696
	9280 - Regulatory Commission Exp	08 - Number of Electric Retail Cust		(0)	(0)				6	6				(6)	(6)				3	3		
		09 - Number of Employees		21	21																	
		28 - Number of Trans Pole Miles							0	0				506	506				456	456		
		39 - 100% to One Company	588,426		588,426			726,060		726,060			331,995		331,995			552,783		552,783		
		39 - 100% to One Company	6,980		6,980			1,293		1,293			2,857		2,857			2,590		2,590		
		48 - MW Generating Capability		(112)	(112)				1,254	1,254				(161)	(161)				81	81		
		58 - Total Assets		12	12				185	185				10,754	10,754				15,926	15,926		
		60 - AEPSC Bill less Indir and Int		2,263	2,263				373	373				1,518	1,518				3,793	3,793		
		61 - Total Fixed Assets		76,127	76,127				54,501	54,501				12,904	12,904				12,495	12,495		
	9280 - Regulatory Commission Exp Total		595,406	78,312	673,718	(111,302)	562,416	727,353	56,319	783,672	(117,034)	666,638	334,852	25,515	360,367	(91)	360,277	555,372	32,754	588,126	(121)	588,005
	9301 - General Advertising Expenses	08 - Number of Electric Retail Cust		8,168	8,168				9,364	9,364				8,793	8,793				8,931	8,931		
		09 - Number of Employees		204	204				123	123												
		39 - 100% to One Company						19		19												
		58 - Total Assets		2,939	2,939				7,273	7,273				6,053	6,053				6,422	6,422		
	9301 - General Advertising Expenses Total			11,312	11,312	(441)	10,871	19	16,760	16,779	(385)	16,394		14,846	14,846	-	14,846		15,353	15,353	-	15,353
	9302 - Misc General Expenses	06 - Number of Commercial Customers		6,790	6,790				7,377	7,377				7,802	7,802				7,795	7,795		
		08 - Number of Electric Retail Cust		11,799	11,799				5,008	5,008				2,613	2,613				1,679	1,679		
		09 - Number of Employees		3,049	3,049				1,606	1,606				1,072	1,072				2,217	2,217		
		11 - Number of GL Transactions		10	10				93	93				44	44				49	49		
		20 - Number of Remittance Items		4	4				6	6												
		28 - Number of Trans Pole Miles		11,653	11,653				10,785	10,785				7,891	7,891				7,595	7,595		
		31 - Number of Vehicles												74	74				74	74		
		32 - Number of Vendor Invoice Pay		312	312				284	284				(87)	(87)				(87)	(87)		
		33 - Number of Workstations		1,485	1,485				54	54				22,128	22,128				9,775	9,775		
		39 - 100% to One Company	66,331		66,331			65,814		65,814			38,593		38,593			47,007		47,007		
		44 - Level of Const-Distribution		146	146																	
		46 - Level of Const-Transmission												110	110				110	110		
		48 - MW Generating Capability		86	86				(114)	(114)				42	42				125	125		
		58 - Total Assets		132,329	132,329				91,343	91,343				96,683	96,683				110,457	110,457		
		60 - AEPSC Bill less Indir and Int		367	367				(354)	(354)				231	231				175	175		
		61 - Total Fixed Assets		71	71				75	75				(7)	(7)				7	7		
		63 - Total Gross Utility Plant		6	6																	
		67 - Number of Banking Transactions							0	0												
		70 - No Nonelectric OAR Invoices		8	8				21	21				14	14				16	16		
	9302 - Misc General Expenses Total		66,331	168,115	234,446	(32,025)	202,421	65,814	116,185	182,000	(14,684)	167,316	38,593	138,608	177,202	(26,040)	151,162	47,007	139,986	186,993	(27,772)	159,221
	9310 - Rents	09 - Number of Employees		556	556				18	18				22	22				22	22		
		32 - Number of Vendor Invoice Pay		326	326				380	380				369	369				367	367		
		33 - Number of Workstations		64,939	64,939				58,752	58,752				51,368	51,368				(8,176)	(8,176)		
		49 - MWH's Generation		1,000	1,000																	
		58 - Total Assets		24,953	24,953				21,134	21,134				24,454	24,454				25,014	25,014		
	9310 - Rents Total			91,774	91,774	(12,250)	79,524		80,285	80,285	(13,540)	66,745		76,213	76,213	(15,349)	60,864		17,227	17,227	(5,282)	11,945
	9350 - Maintenance of General Plant	05 - Number of CIS Customers Mail												400	400				970	970		
		08 - Number of Electric Retail Cust		82,479	82,479				51,225	51,225				99,830	99,830				67,786	67,786		
		09 - Number of Employees		47,121	47,121				9,534	9,534				40,258	40,258				57,205	57,205		
		11 - Number of GL Transactions												19	19				19	19		
		17 - Number of Purchase Orders												9	9				9	9		
		18 - Number of Radios(B/M/HH)		2,047	2,047				2,123	2,123				891	891				547	547		
		21 - Number of Remote Terminal		80	80																	
		27 - Number of Telephones		55,232	55,232				49,355	49,355				58,901	58,901				58,441	58,441		
		28 - Number of Trans Pole Miles		43,170	43,170				4,789	4,789				13,454	13,454				13,829	13,829		
		31 - Number of Vehicles												60	60				60	60		
		32 - Number of Vendor Invoice Pay												21	21				21	21		
		33 - Number of Workstations		426,969	426,969				465,670	465,670				667,908	667,908				669,027	669,027		
		39 - 100% to One Company											18,926		18,926			39,552		39,552		
		39 - 100% to One Company	91,356		91,356			160,403		160,403			166,244		166,244			154,670		154,670		
		40 - Equal Share Ratio		42,009	42,009				(42,542)	(42,542)				254	254				254	254		
		46 - Level of Const-Transmission												11	11				166	166		
		48 - MW Generating Capability		153,245	153,245				78,287	78,287				124,591	124,591				115,344	115,344		
		49 - MWH's Generation		19,850	19,850									735	735				735	735		
		51 - Past 3 Mo MMBTU's Burned (Tot)		24,325	24,325				645	645									15,812	15,812		
		57 - Tons of Fuel Acquired		52	52																	
		58 - Total Assets		138,020	138,020				93,958	93,958				118,484	118,484				127,759	127,759		
		60 - AEPSC Bill less Indir and Int		(269)	(269)				(791)	(791)				1,088	1,088				4,967	4,967		
		61 - Total Fixed Assets		26,676	26,676									65	65				7,463	7,463		
		63 - Total Gross Utility Plant		3	3									40,705	40,705				33,074	33,074		
		64 - Member/Peak Load		71,360	71,360				94,853	94,853				78,701	78,701				84,430	84,430		
	9350 - Maintenance of General Plant Total		91,356	1,132,370	1,223,726	(178,686)	1,045,040	160,403	807,105	967,507	(162,206)	805,302	185,170	1,246,384	1,431,553	(270,297)	1,161,257	194,222	1,257,916	1,452,138	(282,866)	1,169,271
Cost of Service Total			10,256,827	23,592,981	33,849,808	(5,373,935)	28,475,874	13,887,554	21,953,860	35,841,414	(6,489,942)	29,351,472	10,978,384	23,940,240	34,918,624	(6,211,416)	28,707,208	10,926,231	23,252,576	34,178,807	(6,224,534)	27,954,273
Non-Cost of Service	1070 - Construction Work In Progress	03 - Number of Cell Phones/Pagers		1,351	1,351																	
		06 - Number of Commercial Customers		8,440	8,440				4,954	4,954				923	923				923	923		
		08 - Number of Electric Retail Cust		538,990	538,990				779,898	779,898				681,681	681,681				567,259	567,259		
		09 - Number of Employees		324,572	324,572				48,664	48,664				113,581	113,581				119,845	119,845		
		13 - Number of Industrial Customers		12,423	12,423																	
		16 - Number of Phone Center Calls		39,451	39,451				42,370	42,370				49,085	49,085				56,575	56,575		
		17 - Number of Purchase Orders		71,156	71,156				13,393	13,393				1,373	1,373				3,937	3,937		
		18 - Number of Radios(B/M/HH)												5,496	5,496				5,496	5,496		
		26 - Number of Stores Transactions		115,139	115,139				109,006	109,006				8,885	8,885				7,319	7,319		
		27 - Number of Telephones		2,884	2,884									2,815	2,815							
		28 - Number of Trans Pole Miles		191,076	191,076				209,512	209,512				93,448	93,448				85,026	85,026		
		31 - Number of Vehicles							70,310	70,310				56,121	56,121				42,792	42,792		
		32 - Number of Vendor Invoice Pay		14,559	14,559				15,181	15,181				1,916	1,916				22	22		
		33 - Number of Workstations		1,269,725	1,269,725				1,864,159	1,864,159				1,749,961	1,749,961				1,555,609	1,555,609		

Kentucky Power Company
AEPSC Chages by FERC Account, Allocation Factor and Allocation Type, net of share billed to Co-Owner
For 2014,2015,2016 and Test Year Ended February 2017

American Electric Power Service Corporation (AEPSC) is a wholly owned subsidiary of AEP and is the Centralized Service Company for the AEP System. AEPSC's activities are authorized by the FERC under the Public Utilities Holding Company Act of 2005. AEPSC performs, at cost, various corporate support services for subsidiaries of AEP, including Kentucky Power.

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The FERC monitors the factors used for allocations, through required annual reporting, and can audit the validity of each factor. All services are billed at cost, with no profit charged, as required by the FERC's "at cost" rules.

			2014					2015					2016					TEST YEAR				
Account Type	FERC Account	Allocation Factor	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net
		37 - AEPSC Past 3 Months Total Bill		204,602	204,602				240,889	240,889				258,631	258,631				188,169	188,169		
		39 - 100% to One Company	7,689,794		7,689,794			11,026,308		11,026,308			8,809,921		8,809,921			8,191,593		8,191,593		
		40 - Equal Share Ratio		4,511	4,511				10,368	10,368				430	430							
		43 - KWH Sales		1,300	1,300																	
		44 - Level of Const-Distribution		184,210	184,210				155,584	155,584				183,364	183,364				184,704	184,704		
		45 - Level of Const-Production		383,502	383,502				861,075	861,075				1,181,925	1,181,925				1,231,061	1,231,061		
		46 - Level of Const-Transmission		1,573,303	1,573,303				549,463	549,463				592,232	592,232				578,985	578,985		
		48 - MW Generating Capability		239,597	239,597				229,171	229,171				481,108	481,108				490,857	490,857		
		49 - MWH's Generation		110,664	110,664				166,629	166,629				72,362	72,362				70,149	70,149		
		51 - Past 3 Mo MMBTU's Burned (Tot)		20,716	20,716				10,080	10,080				7,151	7,151				6,845	6,845		
		52 - Past 3 Mo MMBTU Burned (Coal)		648	648				111	111				26,597	26,597				45,229	45,229		
		57 - Tons of Fuel Acquired		26,486	26,486				8,355	8,355				16,132	16,132				15,919	15,919		
		58 - Total Assets		396,879	396,879				383,798	383,798				608,057	608,057				637,210	637,210		
		60 - AEPSC Bill less Indir and Int		684,783	684,783				1,221,249	1,221,249				1,601,413	1,601,413				1,355,022	1,355,022		
		61 - Total Fixed Assets		113,287	113,287				247,877	247,877				101,433	101,433				77,905	77,905		
		63 - Total Gross Utility Plant		387,531	387,531				220,913	220,913				1,268,352	1,268,352				1,420,719	1,420,719		
		67 - Number of Banking Transactions		427	427																	
	1070 - Construction Work In Progress Total		7,689,794	6,922,212	14,612,007	(2,372,485)	12,239,522	11,026,308	7,463,008	18,489,316	(2,061,889)	16,427,427	8,809,921	9,164,470	17,974,391	(288,635)	17,685,756	8,191,593	8,747,577	16,939,170	(454,688)	16,484,482
	1080 - Accum Prov for Deprec of Plant	28 - Number of Trans Pole Miles		11	11																	
		37 - AEPSC Past 3 Months Total Bill		9,457	9,457				26,605	26,605				38,837	38,837				38,178	38,178		
		39 - 100% to One Company	462,154		462,154			1,491,414		1,491,414			2,211,425		2,211,425			2,104,078		2,104,078		
		45 - Level of Const-Production							1	1												
		46 - Level of Const-Transmission		18,100	18,100				26,589	26,589				5,532	5,532				5,157	5,157		
		60 - AEPSC Bill less Indir and Int		832	832				203	203				(359)	(359)				2,452	2,452		
	1080 - Accum Prov for Deprec of Plant Total		462,154	28,399	490,553	-	490,553	1,491,414	53,398	1,544,812	(244,069)	1,300,743	2,211,425	44,011	2,255,436	(36,824)	2,218,611	2,104,078	45,787	2,149,865	(230,046)	1,919,819
	1240 - Other Investments	39 - 100% to One Company	209		209			573		573												
	1240 - Other Investments Total		209		209	-	209	573		573	-	573				-	-				-	-
	1520 - Fuel Stock Exp Undistributed	09 - Number of Employees		3,726	3,726				4,200	4,200				3,906	3,906				4,036	4,036		
		28 - Number of Trans Pole Miles							-	-												
		39 - 100% to One Company	502,493		502,493			473,100		473,100			480,204		480,204			477,140		477,140		
		48 - MW Generating Capability		26,805	26,805				2,139	2,139				11,719	11,719				11,391	11,391		
		49 - MWH's Generation												3,306	3,306				7,316	7,316		
		51 - Past 3 Mo MMBTU's Burned (Tot)		10,163	10,163				6,192	6,192				4,772	4,772				5,598	5,598		
		52 - Past 3 Mo MMBTU Burned (Coal)		46,525	46,525				36,080	36,080				20,783	20,783				24,917	24,917		
		57 - Tons of Fuel Acquired		525,026	525,026				483,867	483,867				369,962	369,962				390,349	390,349		
		58 - Total Assets		7,000	7,000				2,445	2,445				7,223	7,223				7,089	7,089		
		60 - AEPSC Bill less Indir and Int		729	729				(550)	(550)				(176)	(176)				974	974		
		63 - Total Gross Utility Plant		572	572				70	70												
		64 - Member/Peak Load		33	33				73	73												
	1520 - Fuel Stock Exp Undistributed Total		502,493	620,579	1,123,072	-	1,123,072	473,100	534,515	1,007,615	-	1,007,615	480,204	421,494	901,699	-	901,699	477,140	451,670	928,810	-	928,810
	1630 - Stores Expense Undistributed	08 - Number of Electric Retail Cust		1	1				488	488				(12)	(12)							
		09 - Number of Employees		43,408	43,408				63,567	63,567				47,846	47,846				48,131	48,131		
		12 - Number of Help Desk Calls		699	699																	
		17 - Number of Purchase Orders		570,192	570,192				1,085,435	1,085,435				1,042,734	1,042,734				1,091,499	1,091,499		
		26 - Number of Stores Transactions		146,403	146,403				206,661	206,661				154,349	154,349				159,807	159,807		
		28 - Number of Trans Pole Miles		3,331	3,331				7,151	7,151				8,654	8,654				9,319	9,319		
		30 - Number of Travel Transactions		0	0																	
		31 - Number of Vehicles		702	702				293	293				274	274				296	296		
		32 - Number of Vendor Invoice Pay		3,065	3,065				2,949	2,949				3,070	3,070				2,813	2,813		
		33 - Number of Workstations		7,608	7,608				9,757	9,757				3,072	3,072				2,377	2,377		
		39 - 100% to One Company	191,999		191,999			275,433		275,433			311,406		311,406			329,299		329,299		
		44 - Level of Const-Distribution												(47)	(47)				242	242		
		46 - Level of Const-Transmission												0	0				0	0		
		48 - MW Generating Capability		71,220	71,220				116,132	116,132				165,735	165,735				235,238	235,238		
		58 - Total Assets		176,553	176,553				139,949	139,949				188,757	188,757				208,667	208,667		
		60 - AEPSC Bill less Indir and Int		4,156	4,156				7,298	7,298				6,039	6,039				618	618		
		61 - Total Fixed Assets		26,799	26,799				31,928	31,928				64,437	64,437				81,166	81,166		
		63 - Total Gross Utility Plant		427	427				27	27				253	253				252	252		
	1630 - Stores Expense Undistributed Total		191,999	1,054,563	1,246,562	-	1,246,562	275,433	1,671,636	1,947,069	-	1,947,069	311,406	1,685,162	1,996,568	-	1,996,568	329,299	1,840,424	2,169,723	-	2,169,723
	1823 - Other Regulatory Assets	08 - Number of Electric Retail Cust												-	-				-	-		
		28 - Number of Trans Pole Miles							-	-												
		39 - 100% to One Company											13		13			13		13		
		58 - Total Assets												(13)	(13)				(13)	(13)		
	1823 - Other Regulatory Assets Total					-	-		-	-	-	-	13	(13)	0	-	0	13	(13)	0	-	0
	1830 - Prelimin Surv&Investgtn Chrgs	28 - Number of Trans Pole Miles							60	60				869	869				946	946		
		39 - 100% to One Company	137,246		137,246								65,828		65,828			93,701		93,701		
		40 - Equal Share Ratio		5,286	5,286									(5,286)	(5,286)				(5,286)	(5,286)		
		48 - MW Generating Capability		1,573	1,573				(254)	(254)				4,052	4,052				6,213	6,213		
		58 - Total Assets		2	2																	
		60 - AEPSC Bill less Indir and Int		(23)	(23)				(20)	(20)				246	246				395	395		
	1830 - Prelimin Surv&Investgtn Chrgs Total		137,246	6,838	144,084	-	144,084		(215)	(215)	-	(215)	65,828	(118)	65,710	-	65,710	93,701	2,267	95,968	-	95,968
	1840 - Clearing Accounts	48 - MW Generating Capability		-	-																	
		52 - Past 3 Mo MMBTU Burned (Coal)		(0)	(0)																	
	1840 - Clearing Accounts Total			(0)	(0)	-	(0)				-	-				-	-				-	-
	1860 - MDD-Internal Billing Only	28 - Number of Trans Pole Miles		-	-				329	329				16	16				0	0		
		39 - 100% to One Company	56,148		56,148			265,276		265,276			778,812		778,812			804,379		804,379		
		60 - AEPSC Bill less Indir and Int		0	0									-	-				-	-		
	1860 - MDD-Internal Billing Only Total		56,148	0	56,148	(4)	56,144	265,276	329	265,605	-	265,605	778,812	16	778,828	-	778,828	804,379	0	804,379	-	804,379
	1880 - R&D Expenses	08 - Number of Electric Retail Cust												792	792				792	792		
		23 - Number of Residential Customer		159	159				3	3												
		28 - Number of Trans Pole Miles		50,963	50,963				46,557	46,557				63,900	63,900				62,049	62,049		
		33 - Number of Workstations		18,482	18,482				25,782	25,782				9,724	9,724				11,323	11,323		
		48 - MW Generating Capability		72,839	72,839				66,622	66,622				47,341	47,341				51,987	51,987		
		49 - MWH's Generation		51	51																	
		51 - Past 3 Mo MMBTU's Burned (Tot)		527,912	527,912				447,383	447,383				297,804	297,804				331,352	331,352		
		52 - Past 3 Mo MMBTU Burned (Coal)		154,010	154,010				36,305	36,305				55,438	55,438				56,479	56,479		
		55 - Past 3 MMBTU Burned (Solid)		10,984	10,984				14,125	14,125				6,109	6,109				3,255	3,255		
		58 - Total Assets		4,896	4,896				16,266	16,266				5,860	5,860				6,298	6,298		
		60 - AEPSC Bill less Indir and Int		321	321				(317)	(317)				335	335				1,855	1,855		
		61 - Total Fixed Assets		49,074	49,074				42,717	42,717				45,870	45,870				48,930	48,930		
	1880 - R&D Expenses Total			889,693	889,693	-	889,693		695,442	695,442	-	695,442		533,175	533,175	-	533,175		574,320	574,320	-	574,320
	2420 - Misc Current & Accrued Liab	48 - MW Generating Capability												(243)	(243)				(243)	(243)		
	2420 - Misc Current & Accrued Liab Total					-	-				-	-		(243)	(243)	-	(243)		(243)	(243)	-	(243)
	4010 - Operation Expense	28 - Number of Trans Pole Miles							0	0				-	-				-	-		
		48 - MW Generating Capability		(0)	(0)																	
		60 - AEPSC Bill less Indir and Int												0	0				0	0		
	4010 - Operation Expense Total			(0)	(0)	-	(0)		0	0	-	0		0	0	-	0		0	0	-	0
	4081 - Taxes Other Than Inc Tax, UOI	39 - 100% to One Company											(16,017)		(16,017)			-		-		
	4081 - Taxes Other Than Inc Tax, UOI Total					-	-				-	-	(16,017)		(16,017)	-	(16,017)	-		-	-	-
	4180 - Non-Operatng Rental Income	39 - 100% to One Company	16		16								2,690		2,690			3,590		3,590		
	4180 - Non-Operatng Rental Income Total		16		16	-	16				-	-	2,690		2,690	-	2,690	3,590		3,590	-	3,590
	4210 - Misc Non-Operating Income	08 - Number of Electric Retail Cust		(0)	(0)				(0)	(0)				0	0				0	0		
		39 - 100% to One Company						-		-												
		40 - Equal Share Ratio		4,163	4,163																	
		58 - Total Assets		2,797	2,797				6,544	6,544				2,802	2,802				2,390	2,390		
		60 - AEPSC Bill less Indir and Int		20	20				157	157				351	351				149	149		
	4210 - Misc Non-Operating Income Total			6,981	6,981	(1,332)	5,649	-	6,701	6,701	(691)	6,010		3,153	3,153	(179)	2,975		2,540	2,540	(90)	2,449
	4261 - Donations	60 - AEPSC Bill less Indir and Int		20,511	20,511				21,830	21,830				43,494	43,494				46,867	46,867		
	4261 - Donations Total			20,511	20,511	(1,916)	18,595		21,830	21,830	(1,558)	20,273		43,494	43,494	-	43,494		46,867	46,867	-	46,867
	4263 - Penalties	09 - Number of Employees																	389	389		
		58 - Total Assets		3	3				105	105				18	18				18	18		
	4263 - Penalties Total			3	3	(0)	3		105	105	(17)	88		18	18	(5)	13		407	407	(95)	312

Kentucky Power Company
AEPSC Chages by FERC Account, Allocation Factor and Allocation Type, net of share billed to Co-Owner
For 2014,2015,2016 and Test Year Ended February 2017

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			2014					2015					2016					TEST YEAR				
Account Type	FERC Account	Allocation Factor	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net	Direct	Allocated	AEPSC Billed to Kentucky Power	Share Billed to Co-Owner	AEPSC Billed to Kentucky Power, Net
	4264 - Civic & Political Activities	08 - Number of Electric Retail Cust		-	-				-	-												
		28 - Number of Trans Pole Miles		-	-				3	3				(3)	(3)				(10)	(10)		
		39 - 100% to One Company						-		-												
		48 - MW Generating Capability		2	2				4	4				(2)	(2)				(15)	(15)		
		58 - Total Assets		189,937	189,937				181,194	181,194				273,249	273,249				266,067	266,067		
		60 - AEPSC Bill less Indir and Int		1,619	1,619				(1,036)	(1,036)				179	179				(719)	(719)		
	4264 - Civic & Political Activities Total			191,559	191,559	(26,581)	164,978	-	180,165	180,165	(12,519)	167,646		273,423	273,423	-	273,423		265,323	265,323	-	265,323
	4265 - Other Deductions	09 - Number of Employees		15	15				6	6				90,314	90,314				90,268	90,268		
		11 - Number of GL Transactions		4	4				6	6												
		17 - Number of Purchase Orders												1	1				1	1		
		27 - Number of Telephones		1	1																	
		28 - Number of Trans Pole Miles		3	3				5	5												
		33 - Number of Workstations		10	10																	
		39 - 100% to One Company	(602)		(602)			-		-												
		40 - Equal Share Ratio		6,997	6,997				257	257												
		48 - MW Generating Capability		226	226				(2)	(2)				58	58				58	58		
		58 - Total Assets		14,048	14,048				31,528	31,528				26,039	26,039				24,133	24,133		
		60 - AEPSC Bill less Indir and Int		40	40				(40)	(40)				-	-				-	-		
		61 - Total Fixed Assets		9	9																	
		63 - Total Gross Utility Plant							22	22												
	4265 - Other Deductions Total		(602)	21,353	20,752	(4,245)	16,506	-	31,783	31,783	(5,156)	26,627		116,413	116,413	(23,890)	92,523		114,461	114,461	(23,814)	90,647
	4540 - Rent From Electric Property	58 - Total Assets												-	-							
	4540 - Rent From Electric Property Total					-	-				-	-		-	-	-	-				-	-
Non-Cost of Service Total			9,039,457	9,762,692	18,802,149	(2,406,564)	16,395,584	13,532,104	10,658,699	24,190,803	(2,325,899)	21,864,904	12,644,281	12,284,456	24,928,738	(349,533)	24,579,205	12,003,792	12,091,386	24,095,179	(708,732)	23,386,446
Grand Total			19,296,284	33,355,673	52,651,957	(7,780,499)	44,871,458	27,419,658	32,612,559	60,032,217	(8,815,841)	51,216,376	23,622,666	36,224,696	59,847,362	(6,560,949)	53,286,412	22,930,024	35,343,962	58,273,985	(6,933,267)	51,340,719

Kentucky Power Company
Other Affiliates Charges by FERC Account, Allocation Factor and Allocation Type
For 2014,2015,2016 and Test Year Ended February 2017

Kentucky Power has a variety of transactions with affiliates on a normal basis. Transactions with affiliates generally fall into two categories. The first category, service payments, is a billing made when an affiliate provides a service to Kentucky Power, such as Appalachian Power providing assistance in distribution maintenance, generation engineering, or other affiliates providing assistance during storm recovery efforts. The second category, convenience payments, occurs when an affiliate company receives an invoice and the cost of that invoice should be borne by multiple AEP companies. For example, a legal invoice for a system-wide issue may be paid by one affiliate company, and that company then bills the other affiliates who benefit from the service.

Charges from affiliates are accumulated using a work order system. All affiliate services and convenience payments are billed to Kentucky Power at cost, per FERC affiliate requirements.

				2014			2015			2016			TEST YEAR		
Account Type	Affiliate	FERC Account	Allocation Factor	Direct	Allocated	Total	Direct	Allocated	Total	Direct	Allocated	Total	Direct	Allocated	Total
Cost of Service	AEP Energy Partners, Inc.	5570 - Other Expenses	49 - MWH's Generation					0	0						
			58 - Total Assets					56,239	56,239		65,385	65,385		65,622	65,622
		9200 - Administrative & Gen Salaries	58 - Total Assets					3,134	3,134		4,204	4,204		4,219	4,219
		9210 - Office Supplies and Expenses	09 - Number of Employees								3	3		3	3
			58 - Total Assets					88	88		329	329		329	329
	AEP Energy Partners, Inc. Total							59,461	59,461		69,921	69,921		70,173	70,173
	AEP Generation Resources	5000 - Oper Supervision & Engineering	39 - 100% to One Company	4,472		4,472	21,592		21,592	21,196		21,196	21,196		21,196
			48 - MW Generating Capability					38	38		317	317		317	317
		5010 - Fuel	39 - 100% to One Company	7		7									
		5020 - Steam Expenses	39 - 100% to One Company	(22,587)		(22,587)									
		5060 - Misc Steam Power Expenses	39 - 100% to One Company	15,783		15,783	614		614	8,435		8,435	8,435		8,435
			40 - Equal Share		430	430		219	219						
			48 - MW Generating Capability		0	0									
		5100 - Maint Supv & Engineering	39 - 100% to One Company	21		21									
			48 - MW Generating Capability		(361)	(361)									
		5110 - Maintenance of Structures	39 - 100% to One Company	16,107		16,107									
		5120 - Maintenance of Boiler Plant	39 - 100% to One Company	(110,077)		(110,077)	38		38	666		666	666		666
		5130 - Maintenance of Electric Plant	39 - 100% to One Company	6,796		6,796	(765)		(765)	630		630	630		630
		5140 - Maintenance of Misc Steam Plt	39 - 100% to One Company	(13,600)		(13,600)									
		5600 - Oper Supervision & Engineering	58 - Total Assets		453	453									
		5880 - Miscellaneous Distribution Exp	08 - Number of Electric Retail Cust		0	0									
		9200 - Administrative & Gen Salaries	58 - Total Assets		62	62					577	577		577	577
		9210 - Office Supplies and Expenses	58 - Total Assets								66	66		138	138
		9230 - Outside Services Employed	08 - No ElecRetailCust Excl 119&211					397	397		298	298		136	136
			09 - Number of Employees		887	887		2,517	2,517		377	377		334	334
			16 - Number of Phone Center Calls		388	388									
			40 - Equal Share		1,178	1,178		528	528						
			58 - Total Assets		80,245	80,245		24,663	24,663		24,179	24,179		26,434	26,434
			61 - Total Fixed Assets		16,426	16,426		8,824	8,824		3,073	3,073		12,073	12,073
		9250 - Injuries and Damages	39 - 100% to One Company	52,181		52,181	356		356	340		340	368		368
			61 - Total Fixed Assets		839	839		4,556	4,556		4,672	4,672		5,208	5,208
		9350 - Maintenance of General Plant	27 - Number of Telephones					1,250	1,250						
	AEP Generation Resources Total			(50,897)	100,546	49,648	21,835	42,990	64,825	31,267	33,559	64,826	31,295	45,218	76,513
	AEP Kentucky Transmission Company, Inc.	9230 - Outside Services Employed	58 - Total Assets								-	-		-	-
	AEP Kentucky Transmission Company, Inc. Total										-	-		-	-
	AEP Texas Central Company	5120 - Maintenance of Boiler Plant	39 - 100% to One Company				(6)		(6)						
		5600 - Oper Supervision & Engineering	09 - Number of Employees					322	322		37	37		37	37
			58 - Total Assets		3,141	3,141		541	541		257	257		260	260
		5660 - Misc Transmission Expenses	09 - Number of Employees		861	861		80	80		32	32		32	32
			39 - 100% to One Company							1,125		1,125	166		166
			58 - Total Assets		0	0		2,461	2,461		2,493	2,493		2,441	2,441
		5680 - Maint Supv & Engineering	09 - Number of Employees								1	1		1	1
		5700 - Maint of Station Equipment	39 - 100% to One Company	70		70									
			58 - Total Assets		8	8									
		5710 - Maintenance of Overhead Lines	08 - Number of Electric Retail Cust								(48)	(48)		(48)	(48)
		5730 - Maint of Misc Trnsmssion Plt	39 - 100% to One Company				10		10						
			58 - Total Assets		3	3		21	21		4	4		4	4
		5800 - Oper Supervision & Engineering	09 - Number of Employees					1	1		2	2		2	2
			61 - Total Fixed Assets		4	4		4	4						
		5810 - Load Dispatching	08 - Number of Electric Retail Cust		11	11									
		5830 - Overhead Line Expenses	39 - 100% to One Company	1		1				42		42	42		42
		5850 - Street Lighting & Signal Sys E	39 - 100% to One Company	269		269									
		5860 - Meter Expenses	08 - Number of Electric Retail Cust		417	417		46	46						
			09 - Number of Employees								28	28		28	28
			39 - 100% to One Company	25		25	190		190	35		35	35		35
		5880 - Miscellaneous Distribution Exp	08 - Number of Electric Retail Cust		1,272	1,272		312	312		130	130		96	96
			09 - Number of Employees		662	662		213	213		335	335		344	344
			39 - 100% to One Company				58		58	3,720		3,720	3,170		3,170
			44 - Level of Const-Distribution		5,039	5,039		5,215	5,215		216	216		129	129
			58 - Total Assets		1,196	1,196		4,143	4,143		70	70		30	30
		5920 - Maint of Station Equipment	39 - 100% to One Company				34		34						
		5930 - Maintenance of Overhead Lines	08 - Number of Electric Retail Cust		5	5									
			39 - 100% to One Company	(84)		(84)	(4)		(4)	(26)		(26)	(26)		(26)
		5940 - Maint of Underground Lines	39 - 100% to One Company							(21)		(21)	(21)		(21)
		5950 - Maint of Lne Trnf,Rglators&Dvi	08 - Number of Electric Retail Cust		57	57									
			09 - Number of Employees								15	15		15	15
			39 - 100% to One Company	(1)		(1)				(21)		(21)	(21)		(21)
		9010 - Supervision - Customer Accts	08 - Number of Electric Retail Cust		159	159									
		9020 - Meter Reading Expenses	58 - Total Assets		359	359									
		9030 - Cust Records & Collection Exp	08 - Number of Electric Retail Cust		234	234									
			39 - 100% to One Company	138		138	20		20	1,426		1,426	1,426		1,426
			58 - Total Assets		45	45									
		9200 - Administrative & Gen Salaries	08 - Number of Electric Retail Cust		1,817	1,817		18	18					1,330	1,330
			09 - Number of Employees		50	50		75	75						
			33 - Number of Workstations		1,545	1,545									
			40 - Equal Share		5	5								21	21
			58 - Total Assets		1,433	1,433					1,803	1,803		2,587	2,587
		9210 - Office Supplies and Expenses	08 - Number of Electric Retail Cust		56	56		0	0					65	65
			09 - Number of Employees		50	50		32	32						
			26 - Number of Stores Transactions								0	0		0	0
			28 - Number of Trans Pole Miles					4	4						
			33 - Number of Workstations		85	85					378	378		316	316
			58 - Total Assets		171	171		32	32		869	869		917	917
		9230 - Outside Services Employed	58 - Total Assets		42	42		184	184		-	-		-	-
		9260 - Employee Pensions & Benefits	09 - Number of Employees								2	2		2	2
		9350 - Maintenance of General Plant	39 - 100% to One Company	182		182	331		331	1,666		1,666	1,666		1,666
	AEP Texas Central Company Total			600	18,726	19,325	634	13,705	14,339	7,946	6,624	14,570	6,437	8,609	15,046
	AEP Texas North Company	5110 - Maintenance of Structures	39 - 100% to One Company				1,158		1,158						
		5120 - Maintenance of Boiler Plant	39 - 100% to One Company				563		563	12		12	12		12
		5390 - Misc Hydr Power Generation Exp	58 - Total Assets		69	69									
		5600 - Oper Supervision & Engineering	09 - Number of Employees		106	106		175	175		41	41		41	41
			58 - Total Assets		1,174	1,174					343	343		343	343
		5620 - Station Expenses	58 - Total Assets								11	11		11	11
		5660 - Misc Transmission Expenses	09 - Number of Employees		1,440	1,440		9	9		29	29		29	29
			39 - 100% to One Company	1,741		1,741				19,630		19,630	21,763		21,763
			58 - Total Assets		0	0		1,470	1,470		1,585	1,585		1,565	1,565
		5710 - Maintenance of Overhead Lines	08 - Number of Electric Retail Cust								(48)	(48)		(48)	(48)
			39 - 100% to One Company										-		-
		5730 - Maint of Misc Trnsmssion Plt	58 - Total Assets					5	5						
		5800 - Oper Supervision & Engineering	09 - Number of Employees		43	43		2	2		1	1		1	1
		5830 - Overhead Line Expenses	39 - 100% to One Company							3		3	3		3
		5880 - Miscellaneous Distribution Exp	08 - Number of Electric Retail Cust		0	0									
			09 - Number of Employees		85	85		4	4		2	2		2	2
			31 - Number of Vehicles					0	0						
		5930 - Maintenance of Overhead Lines	39 - 100% to One Company				38		38	(19)		(19)	(19)		(19)
		5940 - Maint of Underground Lines	39 - 100% to One Company				(5)		(5)	(1)		(1)	(1)		(1)
		5950 - Maint of Lne Trnf,Rglators&Dvi	39 - 100% to One Company				(0)		(0)	(0)		(0)	(0)		(0)
		9030 - Cust Records & Collection Exp	16 - Number of Phone Center Calls		19	19									
		9200 - Administrative & Gen Salaries	08 - Number of Electric Retail Cust		87	87								304	304
			33 - Number of Workstations		807	807		29	29		6	6			
			58 - Total Assets		948	948					343	343		343	343
		9210 - Office Supplies and Expenses	08 - Number of Electric Retail Cust		0	0								73	73
			31 - Number of Vehicles								0	0		0	0
			33 - Number of Workstations		28	28					27	27			
			58 - Total Assets		138	138					98	98		117	117
		9230 - Outside Services Employed	58 - Total Assets		3,471	3,471		18,625	18,625		805	805		1,129	1,129
		9302 - Misc General Expenses	58 - Total Assets								7	7		7	7
		9350 - Maintenance of General Plant	39 - 100% to One Company	76		76									
	AEP Texas North Company Total			1,818	8,413	10,231	1,753	20,318	22,071	19,623	3,251	22,874	21,757	3,916	25,673
	AEP Transmission Company, LLC	5630 - Overhead Line Expenses	58 - Total Assets					1	1						
		5660 - Misc Transmission Expenses	58 - Total Assets		8,152	8,152		7,791	7,791		7,430	7,430		7,430	7,430
		9302 - Misc General Expenses	58 - Total Assets		177	177		8,375	8,375		1,204	1,204			
	AEP Transmission Company, LLC Total				8,329	8,329		16,168	16,168		8,634	8,634		7,430	7,430
	Appalachian Power Company	5000 - Oper Supervision & Engineering	39 - 100% to One Company	2,715		2,715							743		743
			48 - MW Generating Capability		1,155	1,155		17	17		1,081	1,081		1,192	1,192
		5010 - Fuel	39 - 100% to One Company	14,606		14,606									
		5020 - Steam Expenses	39 - 100% to One Company	4,594		4,594									
		5050 - Electric Expenses	39 - 100% to One Company	732		732									
		5060 - Misc Steam Power Expenses	39 - 100% to One Company	45,165		45,165	3,727		3,727	2,609		2,609	2,609		2,609
			40 - Equal Share		27,965	27,965					445	445		445	445
			48 - MW Generating Capability		0	0									
		5100 - Maint Supv & Engineering	39 - 100% to One Company	172,314		172,314	163,080		163,080	143,242		143,242	122,451		122,451
			48 - MW Generating Capability					117	117		691	691		691	691
		5110 - Maintenance of Structures	39 - 100% to One Company	1,669		1,669									
		5120 - Maintenance of Boiler Plant	39 - 100% to One Company	74,447		74,447	4,913		4,913	10,536		10,536	11,323		11,323
		5130 - Maintenance of Electric Plant	39 - 100% to One Company	15,860		15,860	0		0	1,241		1,241	1,241		1,241
		5140 - Maintenance of Misc Steam Plt	39 - 100% to One Company	2,828		2,828									
		5570 - Other Expenses	51 - Past 3 Mo MMBTU's Burned (Tot)		67	67		212	212						
		5600 - Oper Supervision & Engineering	28 - Number of Trans Pole Miles		37	37		6	6					6,710	6,710
			39 - 100% to One Company	18,772		18,772	20,507		20,507	14,711		14,711	14,672		14,672
			58 - Total Assets		1,227	1,227		3,257	3,257		631	631		149	149
		5620 - Station Expenses	39 - 100% to One Company	95,066		95,066									
			58 - Total Assets					66	66						
		5660 - Misc Transmission Expenses	09 - Number of Employees		488	488									
			28 - Number of Trans Pole Miles		3	3		28	28		616	616		614	614
			39 - 100% to One Company	8,983		8,983									
			58 - Total Assets		54	54		(1)	(1)		5	5		2	2
			63 - Total Gross Utility Plant					9	9						
		5680 - Maint Supv & Engineering	58 - Total Assets					74	74		1	1		1	1

Kentucky Power Company
Other Affiliates Charges by FERC Account, Allocation Factor and Allocation Type
For 2014,2015,2016 and Test Year Ended February 2017

Kentucky Power has a variety of transactions with affiliates on a normal basis. Transactions with affiliates generally fall into two categories. The first category, service payments, is a billing made when an affiliate provides a service to Kentucky Power, such as Appalachian Power providing assistance in distribution maintenance, generation engineering, or other affiliates providing assistance during storm recovery efforts. The second category, convenience payments, occurs when an affiliate company receives an invoice and the cost of that invoice should be borne by multiple AEP companies. For example, a legal invoice for a system-wide issue may be paid by one affiliate company, and that company then bills the other affiliates who benefit from the service.

Charges from affiliates are accumulated using a work order system. All affiliate services and convenience payments are billed to Kentucky Power at cost, per FERC affiliate requirements.

					2014			2015			2016			TEST YEAR	
Account Type	Affiliate	FERC Account	Allocation Factor	Direct	Allocated	Total	Direct	Allocated	Total	Direct	Allocated	Total	Direct	Allocated	Total
		5690 - Maintenance of Structures	39 - 100% to One Company	6,403		6,403									
		5700 - Maint of Station Equipment	08 - Number of Electric Retail Cust		3	3					27	27		27	27
			39 - 100% to One Company	53,912		53,912	474		474	562		562	451		451
			58 - Total Assets					41	41						
		5710 - Maintenance of Overhead Lines	08 - Number of Electric Retail Cust		(453)	(453)									
			32 - Number of Vendor Invoice Pay					(23)	(23)						
			39 - 100% to One Company	62,114		62,114	15,996		15,996	3,843		3,843	509		509
			58 - Total Assets		56	56		(25)	(25)						
		5730 - Maint of Misc Trnsmssion Plt	28 - Number of Trans Pole Miles											6	6
			39 - 100% to One Company	3,191		3,191							567		567
			58 - Total Assets					13	13		0	0		0	0
		5800 - Oper Supervision & Engineering	08 - Number of Electric Retail Cust		1,247	1,247		789	789		688	688		669	669
			09 - Number of Employees		762	762		531	531		602	602		607	607
			16 - Number of Phone Center Calls		100	100		15	15		166	166		166	166
			17 - Number of Purchase Orders								6	6		6	6
			33 - Number of Workstations								11	11		11	11
			39 - 100% to One Company	48,519		48,519	25,569		25,569	21,027		21,027	21,997		21,997
			44 - Level of Const-Distribution					873	873		4,169	4,169		3,620	3,620
			58 - Total Assets		37	37		72	72		151	151		64	64
		5820 - Station Expenses	39 - 100% to One Company	25,266		25,266									
		5830 - Overhead Line Expenses	39 - 100% to One Company				166		166	(11)		(11)	21		21
		5860 - Meter Expenses	08 - Number of Electric Retail Cust		133	133		7	7		1	1		1	1
			09 - Number of Employees		16	16									
			39 - 100% to One Company	54,125		54,125	48,648		48,648	78,108		78,108	76,435		76,435
			58 - Total Assets		7	7									
		5870 - Customer Installations Exp	39 - 100% to One Company	285		285				219		219	219		219
		5880 - Miscellaneous Distribution Exp	08 - Number of Electric Retail Cust		4,745	4,745		3,257	3,257		66	66		81	81
			09 - Number of Employees		69	69		63	63		95	95		95	95
			39 - 100% to One Company	15,692		15,692	1,635		1,635	1,752		1,752	2,138		2,138
			44 - Level of Const-Distribution		22	22									
			61 - Total Fixed Assets		(217)	(217)									
		5910 - Maintenance of Structures	39 - 100% to One Company	3,044		3,044									
		5920 - Maint of Station Equipment	39 - 100% to One Company	45,335		45,335	16,658		16,658	33,922		33,922	32,675		32,675
		5930 - Maintenance of Overhead Lines	39 - 100% to One Company	89,825		89,825	14,120		14,120	5,683		5,683	21,222		21,222
		5940 - Maint of Underground Lines	39 - 100% to One Company	(74)		(74)	(10)		(10)	122		122	68		68
		5950 - Maint of Lne Trnf,Rglators&Dvi	08 - Number of Electric Retail Cust					16	16						
			39 - 100% to One Company	25		25	38		38	29		29	118		118
		5970 - Maintenance of Meters	08 - Number of Electric Retail Cust		84	84									
			39 - 100% to One Company	15,539		15,539	1,019		1,019	19		19	19		19
		5980 - Maint of Misc Distribution Plt	08 - Number of Electric Retail Cust		1,094	1,094									
			39 - 100% to One Company							16		16	16		16
		9020 - Meter Reading Expenses	16 - Number of Phone Center Calls		89	89									
			39 - 100% to One Company	132		132	76		76						
		9030 - Cust Records & Collection Exp	08 - Number of Electric Retail Cust		(323)	(323)									
			20 - Number of Remittance Items		1,035	1,035		0	0						
			39 - 100% to One Company	2,607		2,607	493		493	572		572	572		572
		9070 - Supervision - Customer Service	08 - Number of Electric Retail Cust		106	106		39	39		35	35		19	19
		9200 - Administrative & Gen Salaries	08 - Number of Electric Retail Cust		9,594	9,594		9,502	9,502		9,626	9,626		11,188	11,188
			09 - Number of Employees		14	14									
			33 - Number of Workstations		1,942	1,942		146	146		347	347		301	301
			39 - 100% to One Company	26,987		26,987	16,794		16,794	8,537		8,537	6,871		6,871
			48 - MW Generating Capability					39	39						
			58 - Total Assets		358	358		425	425		1,027	1,027		1,357	1,357
		9210 - Office Supplies and Expenses	08 - Number of Electric Retail Cust		114	114		132	132		136	136		311	311
			09 - Number of Employees		90	90									
			17 - Number of Purchase Orders		211	211									
			32 - Number of Vendor Invoice Pay					0	0		4	4		4	4
			33 - Number of Workstations		110	110					146	146		216	216
			39 - 100% to One Company	1,859		1,859	951		951	358		358	216		216
			58 - Total Assets		55	55		14	14		1,105	1,105		1,729	1,729
		9230 - Outside Services Employed	08 - No ElecRetailCust Excl 119&211		130	130					668	668		668	668
			08 - Number of Electric Retail Cust								1,012	1,012		1,229	1,229
			09 - Number of Employees		60	60		717	717		3,717	3,717		4,344	4,344
			33 - Number of Workstations								168	168		199	199
			39 - 100% to One Company	370		370									
			58 - Total Assets		4	4		340	340		14,345	14,345		8,817	8,817
			61 - Total Fixed Assets		514	514		7,363	7,363		18,841	18,841		18,798	18,798
		9240 - Property Insurance	61 - Total Fixed Assets								366	366		366	366
		9250 - Injuries and Damages	58 - Total Assets								525	525			
			61 - Total Fixed Assets		913	913		6,323	6,323		2,308	2,308		2,537	2,537
		9260 - Employee Pensions & Benefits	09 - Number of Employees		20	20									
		9301 - General Advertising Expenses	39 - 100% to One Company				698		698						
		9302 - Misc General Expenses	06 - Number of Commercial Customers								7	7		7	7
			39 - 100% to One Company				5,717		5,717	82,910		82,910	82,910		82,910
			58 - Total Assets		452	452		546	546						
		9310 - Rents	39 - 100% to One Company	17,568		17,568	19,114		19,114	18,864		18,864	18,841		18,841
		9350 - Maintenance of General Plant	39 - 100% to One Company	43,483		43,483	20,676		20,676	32,946		32,946	38,649		38,649
	Appalachian Power Company Total			973,960	54,189	1,028,149	381,058	34,998	416,056	461,816	63,834	525,650	457,551	67,244	524,795
	Cardinal Operating Company	5000 - Oper Supervision & Engineering	48 - MW Generating Capability					11	11						
		5010 - Fuel	39 - 100% to One Company	7,725		7,725	6,647		6,647	5,897		5,897			
		5060 - Misc Steam Power Expenses	39 - 100% to One Company										26		26
		9040 - Uncollectible Accounts	26 - Number of Storeroom Transactio								5	5		5	5
		9230 - Outside Services Employed	61 - Total Fixed Assets		28	28									
		9250 - Injuries and Damages	39 - 100% to One Company	209		209	175		175						
	Cardinal Operating Company Total			7,934	28	7,962	6,822	11	6,833	5,897	5	5,902	26	5	31
	CSW Energy, Inc.	5060 - Misc Steam Power Expenses	48 - MW Generating Capability		725	725									
		5570 - Other Expenses	39 - 100% to One Company	553		553									
			49 - MWH's Generation		18,501	18,501									
			58 - Total Assets		22,078	22,078		2,671	2,671						
		9200 - Administrative & Gen Salaries	58 - Total Assets		4,958	4,958		111	111						
		9210 - Office Supplies and Expenses	17 - Number of Purchase Orders		3	3									
			58 - Total Assets		2	2									
	CSW Energy, Inc. Total			553	46,266	46,819		2,782	2,782						
	Indiana Michigan Power Company	5000 - Oper Supervision & Engineering	09 - Number of Employees								79	79		79	79
			48 - MW Generating Capability		41	41					994	994		994	994
			58 - Total Assets		15	15		35	35						
		5060 - Misc Steam Power Expenses	39 - 100% to One Company	37,895		37,895	291		291	49		49			
			40 - Equal Share		4,877	4,877		3,305	3,305		753	753		593	593
			48 - MW Generating Capability		0	0									
		5100 - Maint Supv & Engineering	48 - MW Generating Capability		60	60									
		5120 - Maintenance of Boiler Plant	39 - 100% to One Company	1,024		1,024	1,212		1,212	1,267		1,267	1,267		1,267
		5130 - Maintenance of Electric Plant	39 - 100% to One Company				221		221	1,231		1,231	722		722
		5570 - Other Expenses	39 - 100% to One Company							26		26	26		26
		5600 - Oper Supervision & Engineering	09 - Number of Employees		(225)	(225)		243	243		94	94		94	94
			58 - Total Assets		3,255	3,255		3,439	3,439		1,260	1,260		1,365	1,365
		5660 - Misc Transmission Expenses	09 - Number of Employees		120	120		35	35		59	59		58	58
			39 - 100% to One Company							86		86	86		86
			58 - Total Assets		50	50		2,777	2,777		2,510	2,510		2,548	2,548
		5680 - Maint Supv & Engineering	09 - Number of Employees								1	1		1	1
		5692 - Maint of Computer Software	33 - Number of Workstations					32	32		56	56		56	56
		5700 - Maint of Station Equipment	39 - 100% to One Company	275		275									
			58 - Total Assets		7	7									
		5710 - Maintenance of Overhead Lines	08 - Number of Electric Retail Cust								(158)	(158)		(158)	(158)
			39 - 100% to One Company				1,100		1,100	392		392	237		237
			58 - Total Assets					9	9						
		5730 - Maint of Misc Trnsmssion Plt	39 - 100% to One Company	103		103									
			58 - Total Assets		16	16		209	209		25	25		23	23
		5800 - Oper Supervision & Engineering	09 - Number of Employees		53	53		11	11		2	2		2	2
			58 - Total Assets		18	18									
		5830 - Overhead Line Expenses	39 - 100% to One Company							44		44	(12)		(12)
		5860 - Meter Expenses	08 - Number of Electric Retail Cust		33	33									
			39 - 100% to One Company							89		89	89		89
		5880 - Miscellaneous Distribution Exp	08 - Number of Electric Retail Cust		240	240					32	32		19	19
			09 - Number of Employees		3,057	3,057		2,223	2,223		102	102		102	102
			17 - Number of Purchase Orders					177	177						
			39 - 100% to One Company	463		463				711		711	299		299
			58 - Total Assets		6,065	6,065		5,709	5,709		769	769		768	768
		5920 - Maint of Station Equipment	39 - 100% to One Company	481		481	1,121		1,121						
		5930 - Maintenance of Overhead Lines	39 - 100% to One Company	128,226		128,226	210,496		210,496	110,663		110,663	206		206
		5940 - Maint of Underground Lines	39 - 100% to One Company				(1)		(1)						
		5950 - Maint of Lne Trnf,Rglators&Dvi	39 - 100% to One Company							0		0	0		0
		5960 - Maint of Strt Lghtng & Sgnal S	39 - 100% to One Company							263		263	263		263
		5980 - Maint of Misc Distribution Plt	39 - 100% to One Company	103		103				23		23	(5)		(5)
			58 - Total Assets		257	257									
		9010 - Supervision - Customer Accts	08 - Number of Electric Retail Cust		198	198									
			58 - Total Assets		18	18									
		9030 - Cust Records & Collection Exp	08 - Number of Electric Retail Cust		173	173									
			16 - Number of Phone Center Calls		10	10									
			39 - 100% to One Company				88		88						
			58 - Total Assets		18	18									
		9080 - Customer Assistance Expenses	08 - Number of Electric Retail Cust		2,603	2,603		3	3						
		9200 - Administrative & Gen Salaries	08 - Number of Electric Retail Cust					138	138		524	524		525	525
			09 - Number of Employees		2,247	2,247		1,225	1,225		993	993		870	870
			33 - Number of Workstations		1,044	1,044		3	3		0	0		0	0
			39 - 100% to One Company							1,353		1,353	1,353		1,353
			58 - Total Assets		586	586		628	628		529	529		731	731
		9210 - Office Supplies and Expenses	08 - Number of Electric Retail Cust		2	2		24	24		61	61		61	61
			09 - Number of Employees		47	47		20	20		25	25		12	12
			17 - Number of Purchase Orders								673	673		468	468

Kentucky Power Company
Other Affiliates Charges by FERC Account, Allocation Factor and Allocation Type
For 2014,2015,2016 and Test Year Ended February 2017

Kentucky Power has a variety of transactions with affiliates on a normal basis. Transactions with affiliates generally fall into two categories. The first category, service payments, is a billing made when an affiliate provides a service to Kentucky Power, such as Appalachian Power providing assistance in distribution maintenance, generation engineering, or other affiliates providing assistance during storm recovery efforts. The second category, convenience payments, occurs when an affiliate company receives an invoice and the cost of that invoice should be borne by multiple AEP companies. For example, a legal invoice for a system-wide issue may be paid by one affiliate company, and that company then bills the other affiliates who benefit from the service.

Charges from affiliates are accumulated using a work order system. All affiliate services and convenience payments are billed to Kentucky Power at cost, per FERC affiliate requirements.

				2014			2015			2016			TEST YEAR		
Account Type	Affiliate	FERC Account	Allocation Factor	Direct	Allocated	Total	Direct	Allocated	Total	Direct	Allocated	Total	Direct	Allocated	Total
			32 - Number of Vendor Invoice Pay								1	1		1	1
			33 - Number of Workstations		171	171					4	4		(0)	(0)
			39 - 100% to One Company							34		34	34		34
			49 - MWH's Generation		0	0									
			58 - Total Assets		20	20		1	1		271	271		919	919
		9230 - Outside Services Employed	09 - Number of Employees					21	21		177	177		166	166
			58 - Total Assets		95	95		9	9		46	46		39	39
			61 - Total Fixed Assets								1	1		1	1
		9250 - Injuries and Damages	39 - 100% to One Company				1,089		1,089						
		9280 - Regulatory Commission Exp	39 - 100% to One Company	784		784									
		9302 - Misc General Expenses	58 - Total Assets		57	57					(1)	(1)		(1)	(1)
		9350 - Maintenance of General Plant	39 - 100% to One Company	291		291	117		117	244		244	280		280
	Indiana Michigan Power Company Total			169,644	25,226	194,870	215,734	20,276	236,010	116,476	9,883	126,359	4,846	10,336	15,182
	Kentucky Power Company	5060 - Misc Steam Power Expenses	39 - 100% to One Company	104		104				1,525		1,525	1,525		1,525
		5130 - Maintenance of Electric Plant	39 - 100% to One Company	8,389		8,389	0		0						
		5140 - Maintenance of Misc Steam Plt	39 - 100% to One Company				15,862		15,862	11,760		11,760	1,530		1,530
		5570 - Other Expenses	39 - 100% to One Company	6,387		6,387	1,792		1,792						
		5620 - Station Expenses	39 - 100% to One Company	1,844		1,844									
		5660 - Misc Transmission Expenses	58 - Total Assets		0	0		16	16					80	80
		5700 - Maint of Station Equipment	39 - 100% to One Company	14,513		14,513	6,433		6,433						
		5710 - Maintenance of Overhead Lines	39 - 100% to One Company	2,106,229		2,106,229	1,321,103		1,321,103	988,797		988,797	922,801		922,801
		5730 - Maint of Misc Trnsmssion Plt	58 - Total Assets					2,369	2,369						
		5820 - Station Expenses	39 - 100% to One Company	136,616		136,616	1		1						
		5880 - Miscellaneous Distribution Exp	39 - 100% to One Company	6,138		6,138	7,331		7,331	628		628	614		614
		5910 - Maintenance of Structures	39 - 100% to One Company	10,284		10,284	23		23						
		5920 - Maint of Station Equipment	39 - 100% to One Company	309,801		309,801	46		46						
		5930 - Maintenance of Overhead Lines	39 - 100% to One Company	10,273		10,273	2,853		2,853	11,746		11,746	5,894		5,894
		5980 - Maint of Misc Distribution Plt	39 - 100% to One Company	1,301		1,301	9		9						
		9080 - Customer Assistance Expenses	39 - 100% to One Company	794		794									
		9120 - Demonstrating & Selling Exp	39 - 100% to One Company							689		689	689		689
		9200 - Administrative & Gen Salaries	33 - Number of Workstations		185	185		10	10		61	61		63	63
			39 - 100% to One Company	809,591		809,591	698,157		698,157	883,586		883,586	876,220		876,220
			58 - Total Assets								40	40		40	40
		9210 - Office Supplies and Expenses	09 - Number of Employees		1	1									
			33 - Number of Workstations		0	0									
			39 - 100% to One Company	73,737		73,737	20,813		20,813	103,386		103,386	119,547		119,547
			58 - Total Assets		2	2					206	206		263	263
		9230 - Outside Services Employed	39 - 100% to One Company	139,656		139,656	103,352		103,352	139,544		139,544	114,753		114,753
			58 - Total Assets		566	566		6	6		9	9		26	26
		9250 - Injuries and Damages	39 - 100% to One Company	2,301		2,301	1,065		1,065						
		9260 - Employee Pensions & Benefits	39 - 100% to One Company				37		37	92		92	92		92
		9280 - Regulatory Commission Exp	39 - 100% to One Company	205,811		205,811	914,609		914,609	102,823		102,823	274,855		274,855
		9301 - General Advertising Expenses	39 - 100% to One Company	20,229		20,229	17,304		17,304	34,373		34,373	33,143		33,143
		9302 - Misc General Expenses	39 - 100% to One Company	138,815		138,815	73,779		73,779	64,698		64,698	66,028		66,028
		9350 - Maintenance of General Plant	39 - 100% to One Company	51,079		51,079	62,672		62,672	55,672		55,672	49,816		49,816
		9090 - Information & Instruct Advrtis	39 - 100% to One Company	53,190		53,190	32,471		32,471	22,076		22,076	23,756		23,756
		9100 - Misc Cust Svc&Informational Ex	39 - 100% to One Company	30,415		30,415	33,058		33,058	19,907		19,907	20,717		20,717
	Kentucky Power Company Total			4,137,497	755	4,138,251	3,312,766	2,401	3,315,167	2,441,301	316	2,441,617	2,511,981	472	2,512,453
	Kingsport Power Company	5600 - Oper Supervision & Engineering	58 - Total Assets		88	88									
		5660 - Misc Transmission Expenses	09 - Number of Employees		0	0		1	1						
			58 - Total Assets		0	0									
		5710 - Maintenance of Overhead Lines	08 - Number of Electric Retail Cust		(16)	(16)									
			58 - Total Assets					(2)	(2)						
		5930 - Maintenance of Overhead Lines	39 - 100% to One Company	1,872		1,872									
		9020 - Meter Reading Expenses	16 - Number of Phone Center Calls		26	26									
		9030 - Cust Records & Collection Exp	05 - Number of CIS Customers Mail		55	55		680	680		(3)	(3)			
			08 - Number of Electric Retail Cust		(17)	(17)									
			39 - 100% to One Company	2,984		2,984	35,834		35,834	(188)		(188)			
		9200 - Administrative & Gen Salaries	08 - Number of Electric Retail Cust											305	305
			58 - Total Assets								28	28		54	54
		9210 - Office Supplies and Expenses	08 - Number of Electric Retail Cust											110	110
			58 - Total Assets								30	30		89	89
		9230 - Outside Services Employed	58 - Total Assets								-	-		-	-
	Kingsport Power Company Total			4,856	136	4,993	35,834	680	36,514	(188)	55	(134)		558	558
	Ohio Power Company	5000 - Oper Supervision & Engineering	48 - MW Generating Capability								19	19		19	19
		5050 - Electric Expenses	39 - 100% to One Company	61		61									
		5060 - Misc Steam Power Expenses	09 - Number of Employees								(1)	(1)		(1)	(1)
			39 - 100% to One Company	0		0	2,976		2,976	129		129	129		129
		5110 - Maintenance of Structures	39 - 100% to One Company							3,106		3,106	(752)		(752)
		5120 - Maintenance of Boiler Plant	39 - 100% to One Company	29		29	6,916		6,916	499		499	499		499
		5600 - Oper Supervision & Engineering	09 - Number of Employees					27	27					0	0
			58 - Total Assets		2,370	2,370		435	435		337	337		292	292
		5620 - Station Expenses	39 - 100% to One Company				150		150						
		5660 - Misc Transmission Expenses	09 - Number of Employees		27	27		0	0						
			58 - Total Assets		139	139		260	260		4,549	4,549		4,519	4,519
		5700 - Maint of Station Equipment	28 - Number of Trans Pole Miles		8	8									
			39 - 100% to One Company	12,021		12,021	10,382		10,382	6,617		6,617	14,685		14,685
		5710 - Maintenance of Overhead Lines	08 - Number of Electric Retail Cust		456	456					(322)	(322)		(322)	(322)
			09 - Number of Employees		67	67		179	179		67	67		67	67
			39 - 100% to One Company							2,737		2,737			
		5730 - Maint of Misc Trnsmssion Plt	09 - Number of Employees		6	6									
			28 - Number of Trans Pole Miles					31	31						
			58 - Total Assets											10	10
		5800 - Oper Supervision & Engineering	08 - Number of Electric Retail Cust		2,004	2,004		1,978	1,978		1,099	1,099		879	879
			09 - Number of Employees		109	109		1,926	1,926		716	716		687	687
			33 - Number of Workstations								112	112		113	113
			39 - 100% to One Company	54,984		54,984	43,376		43,376	39,630		39,630	36,492		36,492
			44 - Level of Const-Distribution		1,000	1,000		61	61		85	85		82	82
			58 - Total Assets		534	534		253	253		238	238		228	228
			61 - Total Fixed Assets					21,165	21,165		69,703	69,703		64,426	64,426
		5830 - Overhead Line Expenses	39 - 100% to One Company							489		489	489		489
		5840 - Underground Line Expenses	39 - 100% to One Company	3,178		3,178	2,853		2,853	3,049		3,049	2,890		2,890
			58 - Total Assets		145	145									
		5860 - Meter Expenses	08 - Number of Electric Retail Cust		302	302		266	266		456	456		405	405
			09 - Number of Employees					89	89					12	12
			39 - 100% to One Company	8,638		8,638	13,184		13,184	7,092		7,092	7,996		7,996
		5870 - Customer Installations Exp	39 - 100% to One Company	287		287				117		117	117		117
		5880 - Miscellaneous Distribution Exp	08 - Number of Electric Retail Cust		6,216	6,216		10,737	10,737		1,393	1,393		1,209	1,209
			09 - Number of Employees		203	203		13,880	13,880		3,705	3,705		3,923	3,923
			17 - Number of Purchase Orders					460	460						
			27 - Number of Telephones					219	219						
			39 - 100% to One Company	6,383		6,383	13,646		13,646	19,561		19,561	20,085		20,085
			44 - Level of Const-Distribution		161	161		184	184		63	63		63	63
			58 - Total Assets		119	119		1,038	1,038		96	96		79	79
		5890 - Rents	39 - 100% to One Company	22		22									
			44 - Level of Const-Distribution		99	99		142	142		95	95		109	109
		5920 - Maint of Station Equipment	39 - 100% to One Company	2,620		2,620	4,458		4,458	2,024		2,024	807		807
		5930 - Maintenance of Overhead Lines	08 - Number of Electric Retail Cust		122	122		25	25		11	11		11	11
			39 - 100% to One Company	46,726		46,726	551,051		551,051	45,869		45,869	458		458
		5940 - Maint of Underground Lines	39 - 100% to One Company				0		0						
		5950 - Maint of Lne Trnf,Rglators&Dvi	39 - 100% to One Company	1		1	12		12	0		0	3		3
		5970 - Maintenance of Meters	08 - Number of Electric Retail Cust		39	39		416	416		208	208		208	208
		5980 - Maint of Misc Distribution Plt	08 - Number of Electric Retail Cust		13	13		38	38						
			39 - 100% to One Company	(0)		(0)				1		1	1		1
		9010 - Supervision - Customer Accts	09 - Number of Employees					95	95		72	72		72	72
		9030 - Cust Records & Collection Exp	05 - Number of CIS Customers Mail		10	10		48	48		22,344	22,344		27,905	27,905
			08 - Number of Electric Retail Cust		(421)	(421)		11	11		39	39		39	39
			09 - Number of Employees					17	17		4	4		4	4
			39 - 100% to One Company	1,108		1,108	807		807	37,686		37,686	37,274		37,274
		9070 - Supervision - Customer Service	09 - Number of Employees					712	712		154	154		154	154
		9080 - Customer Assistance Expenses	08 - Number of Electric Retail Cust		1,344	1,344		78	78						
			09 - Number of Employees					233	233		51	51		39	39
		9110 - Supervision - Sales Expenses	08 - Number of Electric Retail Cust					262	262		110	110		154	154
			09 - Number of Employees					196	196						
		9200 - Administrative & Gen Salaries	08 - Number of Electric Retail Cust		667	667		953	953		11,176	11,176		11,285	11,285
			09 - Number of Employees		1,797	1,797		537	537		177	177		175	175
			11 - Number of GL Transactions								88	88		261	261
			33 - Number of Workstations		1,257	1,257		0	0		77	77		55	55
			39 - 100% to One Company	2,579		2,579				39		39	39		39
			58 - Total Assets		378	378		231	231		821	821		920	920
			61 - Total Fixed Assets		202	202									
		9210 - Office Supplies and Expenses	08 - Number of Electric Retail Cust					0	0		264	264		264	264
			09 - Number of Employees		17	17		9	9		0	0		0	0
			11 - Number of GL Transactions											0	0
			32 - Number of Vendor Invoice Pay								0	0		0	0
			33 - Number of Workstations		49	49									
			39 - 100% to One Company	18		18									
			58 - Total Assets		471	471		330	330		446	446		549	549
		9230 - Outside Services Employed	08 - No ElecRetailCust Excl 119&211		176	176		762	762		412	412		463	463
			08 - Number of Electric Retail Cust					452	452		594	594		594	594
			09 - Number of Employees					3,408	3,408		541	541		350	350
			17 - Number of Purchase Orders		110	110									
			58 - Total Assets		1,885	1,885		538	538		879	879		834	834
			61 - Total Fixed Assets		1,232	1,232		11	11		22,003	22,003		22,003	22,003
		9302 - Misc General Expenses	08 - No ElecRetailCust Excl 119&211		(1,614)	(1,614)									
			08 - Number of Electric Retail Cust		(374)	(374)									
			39 - 100% to One Company	0		0	22,506		22,506						
		9350 - Maintenance of General Plant	09 - Number of Employees					81	81						
			39 - 100% to One Company	6,370		6,370	15,241		15,241	4,401		4,401	2,926		2,926

Kentucky Power Company
Other Affiliates Charges by FERC Account, Allocation Factor and Allocation Type
For 2014,2015,2016 and Test Year Ended February 2017

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Charges from affiliates are accumulated using a work order system. All affiliate services and convenience payments are billed to Kentucky Power at cost, per FERC affiliate requirements.

				2014			2015			2016			TEST YEAR		
Account Type	Affiliate	FERC Account	Allocation Factor	Direct	Allocated	Total	Direct	Allocated	Total	Direct	Allocated	Total	Direct	Allocated	Total
	Ohio Power Company Total			145,026	21,328	166,354	687,560	62,774	750,334	173,044	142,881	315,925	124,139	143,137	267,275
	Public Service Company of Oklahoma	5000 - Oper Supervision & Engineering	17 - Number of Purchase Orders					31	31						
			48 - MW Generating Capability		1,261	1,261		597	597		2,138	2,138		2,443	2,443
		5020 - Steam Expenses	39 - 100% to One Company	294		294									
		5060 - Misc Steam Power Expenses	39 - 100% to One Company	1,148		1,148	36		36						
			40 - Equal Share		685	685		661	661		844	844		844	844
			48 - MW Generating Capability		64	64									
			58 - Total Assets		1	1									
		5110 - Maintenance of Structures	39 - 100% to One Company							684		684	684		684
		5120 - Maintenance of Boiler Plant	39 - 100% to One Company				117		117						
		5600 - Oper Supervision & Engineering	09 - Number of Employees					257	257		106	106		106	106
			58 - Total Assets		1,938	1,938		342	342		249	249		318	318
		5660 - Misc Transmission Expenses	09 - Number of Employees		324	324		201	201		184	184		161	161
			39 - 100% to One Company	8,685		8,685									
			58 - Total Assets		35	35		1,909	1,909		1,834	1,834		1,834	1,834
		5680 - Maint Supv & Engineering	09 - Number of Employees								0	0		0	0
		5710 - Maintenance of Overhead Lines	08 - Number of Electric Retail Cust								(190)	(190)		(190)	(190)
		5730 - Maint of Misc Trnsmssion Plt	58 - Total Assets					8	8		25	25		21	21
		5800 - Oper Supervision & Engineering	08 - Number of Electric Retail Cust		26	26									
			09 - Number of Employees		15	15		1,787	1,787		21	21		19	19
			44 - Level of Const-Distribution		30	30		34	34						
			58 - Total Assets		4,277	4,277		3,771	3,771						
		5830 - Overhead Line Expenses	48 - MW Generating Capability		(135)	(135)									
		5860 - Meter Expenses	16 - Number of Phone Center Calls		1	1									
			39 - 100% to One Company				52		52						
		5880 - Miscellaneous Distribution Exp	08 - Number of Electric Retail Cust		776	776		53	53		72	72		72	72
			09 - Number of Employees		902	902		1,258	1,258		1,948	1,948		1,867	1,867
			39 - 100% to One Company	2,918		2,918									
			44 - Level of Const-Distribution		2	2									
			58 - Total Assets		242	242		217	217		184	184		184	184
		5930 - Maintenance of Overhead Lines	39 - 100% to One Company	267		267	104		104						
		5950 - Maint of Lne Trnf,Rglators&Dvi	39 - 100% to One Company	2		2									
		9010 - Supervision - Customer Accts	08 - Number of Electric Retail Cust		105	105									
			09 - Number of Employees		20	20									
		9020 - Meter Reading Expenses	08 - Number of Electric Retail Cust		94	94									
		9030 - Cust Records & Collection Exp	08 - Number of Electric Retail Cust		8	8		24	24		6	6		6	6
			16 - Number of Phone Center Calls		36	36									
			39 - 100% to One Company	(110)		(110)				587		587	587		587
		9040 - Uncollectible Accounts	26 - Number of Storeroom Transactio								48	48		48	48
		9080 - Customer Assistance Expenses	08 - Number of Electric Retail Cust		318	318		3	3						
		9120 - Demonstrating & Selling Exp	08 - Number of Electric Retail Cust		137	137		86	86						
		9200 - Administrative & Gen Salaries	08 - Number of Electric Retail Cust		91	91		4	4					1,480	1,480
			09 - Number of Employees		104	104									
			33 - Number of Workstations		1,222	1,222		168	168						
			58 - Total Assets		379	379		40	40						
		9210 - Office Supplies and Expenses	08 - Number of Electric Retail Cust		(0)	(0)		3	3					174	174
			09 - Number of Employees		22	22									
			28 - Number of Trans Pole Miles					3	3						
			32 - Number of Vendor Invoice Pay								1	1		1	1
			33 - Number of Workstations		73	73									
			58 - Total Assets		0	0					136	136		148	148
		9230 - Outside Services Employed	09 - Number of Employees		681	681		769	769						
			58 - Total Assets		618	618		39	39		22	22		22	22
		9250 - Injuries and Damages	39 - 100% to One Company							2,467		2,467	2,467		2,467
	Public Service Company of Oklahoma Total			13,204	14,347	27,552	309	12,267	12,575	3,738	7,626	11,363	3,738	9,559	13,296
	Southwestern Electric Power Company	5000 - Oper Supervision & Engineering	48 - MW Generating Capability					17	17		4,309	4,309		4,731	4,731
		5060 - Misc Steam Power Expenses	39 - 100% to One Company	54,065		54,065									
			40 - Equal Share		358	358		141	141		905	905		905	905
			48 - MW Generating Capability		3	3									
			52 - Past 3 Mo MMBTU Burned (Coal)		2,480	2,480		6,347	6,347						
		5120 - Maintenance of Boiler Plant	39 - 100% to One Company	1,714		1,714	212		212	261		261	481		481
		5130 - Maintenance of Electric Plant	39 - 100% to One Company							114		114	114		114
		5570 - Other Expenses	51 - Past 3 Mo MMBTU's Burned (Tot)					822	822						
		5600 - Oper Supervision & Engineering	09 - Number of Employees		217	217		188	188		22	22		14	14
			58 - Total Assets		1,518	1,518		19	19		89	89		71	71
			61 - Total Fixed Assets		(0)	(0)		3	3		(1)	(1)		(0)	(0)
		5612 - Load Dispatch-Mntr&Op TransSys	28 - Number of Trans Pole Miles		58	58									
			58 - Total Assets		4	4									
		5630 - Overhead Line Expenses	09 - Number of Employees								19	19		19	19
			58 - Total Assets								9	9		20	20
		5660 - Misc Transmission Expenses	09 - Number of Employees		188	188		10	10		57	57		56	56
			39 - 100% to One Company	12,752		12,752									
			40 - Equal Share		0	0									
			58 - Total Assets		35	35		1,731	1,731		1,721	1,721		1,721	1,721
		5710 - Maintenance of Overhead Lines	08 - Number of Electric Retail Cust		(469)	(469)									
			58 - Total Assets					(31)	(31)						
		5730 - Maint of Misc Trnsmssion Plt	58 - Total Assets					27	27		11	11		11	11
		5800 - Oper Supervision & Engineering	09 - Number of Employees		17	17		2	2		3	3		3	3
			61 - Total Fixed Assets		(0)	(0)		1	1		(0)	(0)		(0)	(0)
		5860 - Meter Expenses	08 - Number of Electric Retail Cust		42	42									
			09 - Number of Employees		1	1									
			39 - 100% to One Company	7		7	80		80	1,343		1,343	1,343		1,343
		5880 - Miscellaneous Distribution Exp	08 - Number of Electric Retail Cust		409	409		877	877		426	426		157	157
			09 - Number of Employees		163	163		2,187	2,187		83	83		83	83
			39 - 100% to One Company	16,233		16,233	25,231		25,231	28,726		28,726	28,546		28,546
			58 - Total Assets		9,892	9,892		12,473	12,473						
		5920 - Maint of Station Equipment	39 - 100% to One Company	466		466									
		5930 - Maintenance of Overhead Lines	39 - 100% to One Company	1,494		1,494	1,378		1,378	1,343		1,343	1,618		1,618
		5940 - Maint of Underground Lines	39 - 100% to One Company				0		0	(3)		(3)	(6)		(6)
		5950 - Maint of Lne Trnf,Rglators&Dvi	39 - 100% to One Company				(15)		(15)				3		3
		9010 - Supervision - Customer Accts	08 - Number of Electric Retail Cust		143	143									
			58 - Total Assets		86	86									
		9030 - Cust Records & Collection Exp	08 - Number of Electric Retail Cust		(189)	(189)		0	0						
			39 - 100% to One Company	(23)		(23)				1,214		1,214	1,214		1,214
			58 - Total Assets		8	8		15	15		12	12		10	10
		9070 - Supervision - Customer Service	08 - Number of Electric Retail Cust		47	47									
			16 - Number of Phone Center Calls		5	5									
		9080 - Customer Assistance Expenses	08 - Number of Electric Retail Cust		2,400	2,400		0	0						
		9200 - Administrative & Gen Salaries	08 - Number of Electric Retail Cust								435	435		1,925	1,925
			33 - Number of Workstations		1,990	1,990		1	1						
			58 - Total Assets		1,721	1,721					1,036	1,036		1,105	1,105
			61 - Total Fixed Assets		201	201									
		9210 - Office Supplies and Expenses	08 - Number of Electric Retail Cust		5	5		4	4		190	190		281	281
			09 - Number of Employees		16	16									
			28 - Number of Trans Pole Miles		3	3		5	5						
			33 - Number of Workstations		423	423									
			39 - 100% to One Company							1,950		1,950	1,950		1,950
			48 - MW Generating Capability		335	335		(7)	(7)						
			58 - Total Assets		139	139					178	178		195	195
			61 - Total Fixed Assets								13	13		13	13
		9230 - Outside Services Employed	09 - Number of Employees					798	798		1,196	1,196		1,133	1,133
			58 - Total Assets		741	741		435	435		141	141		141	141
		9260 - Employee Pensions & Benefits	28 - Number of Trans Pole Miles		7	7									
	Southwestern Electric Power Company Total			86,709	22,996	109,704	26,886	26,066	52,952	34,948	10,855	45,802	35,264	12,595	47,859
	Wheeling Power Company	5730 - Maint of Misc Trnsmssion Plt	58 - Total Assets					13	13						
		5880 - Miscellaneous Distribution Exp	08 - Number of Electric Retail Cust		181	181									
		5930 - Maintenance of Overhead Lines	39 - 100% to One Company				32		32						
		5940 - Maint of Underground Lines	39 - 100% to One Company				0		0						
		5950 - Maint of Lne Trnf,Rglators&Dvi	39 - 100% to One Company				0		0						
		9030 - Cust Records & Collection Exp	08 - Number of Electric Retail Cust		(15)	(15)									
		9200 - Administrative & Gen Salaries	08 - Number of Electric Retail Cust											101	101
		9210 - Office Supplies and Expenses	08 - Number of Electric Retail Cust											21	21
		9230 - Outside Services Employed	58 - Total Assets								-	-		-	-
	Wheeling Power Company Total				166	166	32	13	45		-	-		121	121
	Other	5000 - Oper Supervision & Engineering	09 - Number of Employees		120	120									
			48 - MW Generating Capability								91	91		91	91
		5010 - Fuel	39 - 100% to One Company							-		-	-		-
		5600 - Oper Supervision & Engineering	58 - Total Assets		7	7		30	30		65	65		2	2
		5660 - Misc Transmission Expenses	58 - Total Assets					15	15		130	130		112	112
		9210 - Office Supplies and Expenses	58 - Total Assets								29	29		29	29
		9230 - Outside Services Employed	58 - Total Assets		0	0					(0)	(0)		(0)	(0)
	Other Total				127	127		45	45	-	316	316	-	234	234
Cost of Service Total				5,490,903	321,578	5,812,481	4,691,222	314,954	5,006,176	3,295,867	357,758	3,653,625	3,197,033	379,606	3,576,639
Non-Cost of Service	AEP Generation Resources	1070 - Construction Work In Progress	39 - 100% to One Company	454,675		454,675	(55,394)		(55,394)	1,030		1,030	1,030		1,030
		1080 - Accum Prov for Deprec of Plant	39 - 100% to One Company	(3,005,028)		(3,005,028)									
		1510 - Fuel Stock	39 - 100% to One Company	(972,003)		(972,003)									
		1520 - Fuel Stock Exp Undistributed	39 - 100% to One Company	(110,871)		(110,871)				2,498		2,498	2,498		2,498
		1540 - Materials & Oper Supplies	39 - 100% to One Company	98,016		98,016	2,074		2,074						
		1650 - Prepayments	39 - 100% to One Company	117,441		117,441									
		1750 - Curr. Unreal Gains - NonAffil	39 - 100% to One Company	(167,738)		(167,738)									
		1830 - Prelimin Surv&Investgtn Chrgs	39 - 100% to One Company	(5,511)		(5,511)									
		1840 - Clearing Accounts	63 - Total Gross Utility Plant								911	911		911	911
		1860 - MDD-Internal Billing Only	39 - 100% to One Company	(2,128)		(2,128)									
		2300 - Asset Retirement Obligations	39 - 100% to One Company	79,484		79,484									
		4030 - Depreciation Expense	39 - 100% to One Company	2,849,955		2,849,955									
		4031 - Depreciation Expense for Asset Retirement Costs	39 - 100% to One Company	134,664		134,664									
		4111 - Prov Def I/T-Cr Util Oper Inc	39 - 100% to One Company	(79,484)		(79,484)									
		4261 - Donations	58 - Total Assets								170	170		170	170
		4265 - Other Deductions	58 - Total Assets					94	94						

Kentucky Power Company
Other Affiliates Charges by FERC Account, Allocation Factor and Allocation Type
For 2014,2015,2016 and Test Year Ended February 2017

Kentucky Power has a variety of transactions with affiliates on a normal basis. Transactions with affiliates generally fall into two categories. The first category, service payments, is a billing made when an affiliate provides a service to Kentucky Power, such as Appalachian Power providing assistance in distribution maintenance, generation engineering, or other affiliates providing assistance during storm recovery efforts. The second category, convenience payments, occurs when an affiliate company receives an invoice and the cost of that invoice should be borne by multiple AEP companies. For example, a legal invoice for a system-wide issue may be paid by one affiliate company, and that company then bills the other affiliates who benefit from the service.

Charges from affiliates are accumulated using a work order system. All affiliate services and convenience payments are billed to Kentucky Power at cost, per FERC affiliate requirements.

				2014			2015			2016			TEST YEAR		
Account Type	Affiliate	FERC Account	Allocation Factor	Direct	Allocated	Total	Direct	Allocated	Total	Direct	Allocated	Total	Direct	Allocated	Total
		4560 - Other Electric Revenues	39 - 100% to One Company	988		988									
	AEP Generation Resources Total			(607,541)		(607,541)	(53,320)	94	(53,226)	3,528	1,081	4,609	3,528	1,081	4,609
	AEP Kentucky Transmission Company, Inc.	1070 - Construction Work In Progress	39 - 100% to One Company				38,531		38,531						
	AEP Kentucky Transmission Company, Inc. Total						38,531		38,531						
	AEP Texas Central Company	1070 - Construction Work In Progress	39 - 100% to One Company	(688)		(688)	251		251	209		209	209		209
			58 - Total Assets		25	25		1	1						
		1080 - Accum Prov for Deprec of Plant	39 - 100% to One Company	(2)		(2)	91		91	42		42	42		42
		1840 - Clearing Accounts	08 - Number of Electric Retail Cust		20	20									
			09 - Number of Employees					3	3		8	8		8	8
			31 - Number of Vehicles		199	199		78	78		189	189		187	187
			39 - 100% to One Company	21		21									
			58 - Total Assets		132	132									
		1860 - MDD-Internal Billing Only	39 - 100% to One Company	94		94	103		103						
	AEP Texas Central Company Total			(574)	375	(199)	444	82	526	251	196	447	251	195	446
	AEP Texas North Company	1070 - Construction Work In Progress	39 - 100% to One Company	212		212	(6)		(6)	12		12	12		12
		1080 - Accum Prov for Deprec of Plant	39 - 100% to One Company				(0)		(0)	1		1	1		1
		1840 - Clearing Accounts	31 - Number of Vehicles		206	206		22	22		80	80		81	81
			58 - Total Assets					1	1						
	AEP Texas North Company Total			212	206	418	(6)	23	18	13	80	93	13	81	94
	AEP Transmission Company, LLC	1070 - Construction Work In Progress	58 - Total Assets					12	12		35	35		35	35
		4261 - Donations	58 - Total Assets					67	67		858	858		858	858
	AEP Transmission Company, LLC Total							79	79		893	893		893	893
	Appalachian Power Company	1070 - Construction Work In Progress	39 - 100% to One Company	224,350		224,350	261,749		261,749	261,497		261,497	267,560		267,560
			58 - Total Assets		56	56		1	1		4	4			
		1080 - Accum Prov for Deprec of Plant	39 - 100% to One Company	12,763		12,763	13,547		13,547	7,527		7,527	7,557		7,557
		1520 - Fuel Stock Exp Undistributed	39 - 100% to One Company	753		753									
		1740 - Misc Current & Accrued Assets	58 - Total Assets					1	1						
		1750 - Curr. Unreal Gains - NonAffil	39 - 100% to One Company	(21,768)		(21,768)									
		1830 - Prelimin Surv&Investgtn Chrgs	48 - MW Generating Capability								(9)	(9)		(9)	(9)
		1840 - Clearing Accounts	08 - Number of Electric Retail Cust		132	132		355	355						
			09 - Number of Employees		62	62		102	102		1,135	1,135		1,068	1,068
			31 - Number of Vehicles		2,027	2,027		797	797		485	485		486	486
			39 - 100% to One Company	28,590		28,590	4,825		4,825	325		325	79		79
			52 - Past 3 Mo MMBTU Burned (Coal)											145	145
			58 - Total Assets		892	892		7	7						
			61 - Total Fixed Assets					196	196		535	535		489	489
			63 - Total Gross Utility Plant								2,786	2,786		2,786	2,786
		1850 - Temporary Facilities	39 - 100% to One Company				55		55						
		1860 - MDD-Internal Billing Only	39 - 100% to One Company	4,129		4,129	1		1	297		297	297		297
		1880 - R&D Expenses	28 - Number of Trans Pole Miles								1	1		1	1
			58 - Total Assets					262	262		404	404		94	94
		2540 - Other Regulatory Liabilities	39 - 100% to One Company	3,697,441		3,697,441									
		4210 - Misc Non-Operating Income	39 - 100% to One Company							(901)		(901)	(901)		(901)
		4261 - Donations	58 - Total Assets		18	18									
		4560 - Other Electric Revenues	39 - 100% to One Company	(86,152)		(86,152)	(126,016)		(126,016)	(89,842)		(89,842)	(88,296)		(88,296)
	Appalachian Power Company Total			3,860,107	3,187	3,863,295	154,162	1,720	155,882	178,903	5,342	184,244	186,296	5,061	191,357
	CSW Energy, Inc.	1520 - Fuel Stock Exp Undistributed	51 - Past 3 Mo MMBTU's Burned (Tot)		872	872									
	CSW Energy, Inc. Total				872	872									
	Indiana Michigan Power Company	1070 - Construction Work In Progress	39 - 100% to One Company	38,400		38,400	19,258		19,258	14,041		14,041	763		763
			58 - Total Assets					5	5		5	5		5	5
		1080 - Accum Prov for Deprec of Plant	39 - 100% to One Company	8,343		8,343	5,913		5,913	6,515		6,515	66		66
		1830 - Prelimin Surv&Investgtn Chrgs	48 - MW Generating Capability								(8)	(8)		(8)	(8)
		1840 - Clearing Accounts	09 - Number of Employees								28	28		28	28
			31 - Number of Vehicles		107	107		1,245	1,245		710	710		629	629
			39 - 100% to One Company	419		419	4,421		4,421						
			52 - Past 3 Mo MMBTU Burned (Coal)											48	48
			58 - Total Assets					50	50						
			63 - Total Gross Utility Plant								35,816	35,816		47,084	47,084
		1860 - MDD-Internal Billing Only	39 - 100% to One Company							44,731		44,731	44,731		44,731
			58 - Total Assets					(2)	(2)						
		1880 - R&D Expenses	51 - Past 3 Mo MMBTU's Burned (Tot)					8	8						
			60 - Payroll - AEPSC less Indir&Int					(0)	(0)						
	Indiana Michigan Power Company Total			47,162	107	47,269	29,592	1,305	30,897	65,287	36,551	101,838	45,560	47,786	93,347
	Kentucky Power Company	1070 - Construction Work In Progress	39 - 100% to One Company	1,598,033		1,598,033	1,780,174		1,780,174	943,330		943,330	995,191		995,191
		1080 - Accum Prov for Deprec of Plant	39 - 100% to One Company	28,149		28,149	9,236		9,236	985		985	792		792
		1830 - Prelimin Surv&Investgtn Chrgs	39 - 100% to One Company	433		433									
		1840 - Clearing Accounts	09 - Number of Employees								1	1		1	1
			31 - Number of Vehicles		252	252		2	2		20	20		20	20
			39 - 100% to One Company	245		245									
			58 - Total Assets		114	114		0	0						
			63 - Total Gross Utility Plant								81	81		81	81
		1860 - MDD-Internal Billing Only	39 - 100% to One Company	484		484				8,666		8,666	7,383		7,383
		1880 - R&D Expenses	39 - 100% to One Company	200,000		200,000	200,000		200,000						
		4261 - Donations	39 - 100% to One Company	187,925		187,925	17,587		17,587	25,737		25,737	16,648		16,648
		4265 - Other Deductions	39 - 100% to One Company	177,347		177,347	31,309		31,309	43,767		43,767	21,668		21,668
		4264 - Civic & Political Activities	39 - 100% to One Company	85,650		85,650	107,726		107,726	152,602		152,602	163,460		163,460
		4310 - Other Interest Expense	39 - 100% to One Company	262,013		262,013	168,255		168,255	196,301		196,301	206,723		206,723
		4081 - Taxes Other Than Inc Tax, UOI	39 - 100% to One Company							(0)		(0)	(0)		(0)
	Kentucky Power Company Total			2,540,279	366	2,540,644	2,314,287	2	2,314,289	1,371,387	103	1,371,490	1,411,864	103	1,411,967
	Kingsport Power Company	1070 - Construction Work In Progress	39 - 100% to One Company	12,312		12,312	7		7						
		1080 - Accum Prov for Deprec of Plant	39 - 100% to One Company	38		38									
		1840 - Clearing Accounts	09 - Number of Employees								97	97		98	98
			31 - Number of Vehicles		209	209		309	309		38	38		38	38
			39 - 100% to One Company	10,539		10,539				6		6			
	Kingsport Power Company Total			22,890	209	23,098	7	309	316	6	135	141		136	136
	Ohio Power Company	1070 - Construction Work In Progress	39 - 100% to One Company	64,179		64,179	179,516		179,516	13,665		13,665	791		791
			58 - Total Assets					1	1						
		1080 - Accum Prov for Deprec of Plant	39 - 100% to One Company	2,362		2,362	19,513		19,513	2,694		2,694	21		21
		1430 - Other Accounts Receivable	58 - Total Assets		(0)	(0)									
		1740 - Misc Current & Accrued Assets	58 - Total Assets					(4)	(4)						
		1840 - Clearing Accounts	08 - Number of Electric Retail Cust		133	133		191	191						
			31 - Number of Vehicles		2,859	2,859		17,798	17,798		17,017	17,017		16,614	16,614
			39 - 100% to One Company	270		270	4,798		4,798	2,585		2,585	884		884
			58 - Total Assets		295	295		62	62						
			63 - Total Gross Utility Plant								38	38		38	38
		1860 - MDD-Internal Billing Only	09 - Number of Employees					45	45						
			39 - 100% to One Company	11,688		11,688	24,238		24,238						
			58 - Total Assets					4	4		(0)	(0)		(0)	(0)
		1880 - R&D Expenses	60 - Payroll - AEPSC less Indir&Int		0	0									
			61 - Total Fixed Assets		107	107									
		2540 - Other Regulatory Liabilities	39 - 100% to One Company	22,681		22,681									
		4540 - Rent From Electric Property	39 - 100% to One Company	(12,897)		(12,897)	(12,897)		(12,897)	(12,897)		(12,897)	(12,897)		(12,897)
		4560 - Other Electric Revenues	39 - 100% to One Company	(6,752)		(6,752)	(10,009)		(10,009)	(8,427)		(8,427)	(9,218)		(9,218)
	Ohio Power Company Total			81,531	3,394	84,925	205,160	18,096	223,256	(2,379)	17,054	14,675	(20,418)	16,651	(3,767)
	Public Service Company of Oklahoma	1070 - Construction Work In Progress	39 - 100% to One Company	19		19	3,401		3,401	1,230		1,230	48		48
		1080 - Accum Prov for Deprec of Plant	39 - 100% to One Company	5		5	235		235						
		1520 - Fuel Stock Exp Undistributed	39 - 100% to One Company	127		127				2,164		2,164	1		1
		1830 - Prelimin Surv&Investgtn Chrgs	48 - MW Generating Capability								13	13		13	13
		1840 - Clearing Accounts	08 - Number of Electric Retail Cust					202	202						
			09 - Number of Employees								760	760		760	760
			31 - Number of Vehicles					28	28		234	234		235	235
			39 - 100% to One Company				4		4						
			63 - Total Gross Utility Plant								99	99		99	99
		1860 - MDD-Internal Billing Only	39 - 100% to One Company										2,970		2,970
		1880 - R&D Expenses	48 - MW Generating Capability		170	170									
			60 - Payroll - AEPSC less Indir&Int					0	0		(0)	(0)		(0)	(0)
			61 - Total Fixed Assets					375	375		480	480		608	608
	Public Service Company of Oklahoma Total			150	170	321	3,641	605	4,246	3,394	1,587	4,981	3,019	1,715	4,734
	Southwestern Electric Power Company	1070 - Construction Work In Progress	39 - 100% to One Company	294		294	103		103	(849)		(849)	(800)		(800)
			58 - Total Assets								0	0		0	0
		1080 - Accum Prov for Deprec of Plant	39 - 100% to One Company	69		69	25		25	117		117	127		127
		1520 - Fuel Stock Exp Undistributed	39 - 100% to One Company							733		733	733		733
		1750 - Curr. Unreal Gains - NonAffil	39 - 100% to One Company	(442,339)		(442,339)									
		1830 - Prelimin Surv&Investgtn Chrgs	48 - MW Generating Capability								10	10		10	10
		1840 - Clearing Accounts	08 - Number of Electric Retail Cust		257	257									
			09 - Number of Employees								102	102		102	102
			31 - Number of Vehicles		1,513	1,513		59	59		221	221		221	221
			39 - 100% to One Company	7		7	2		2						
			58 - Total Assets		716	716		60	60						
			61 - Total Fixed Assets		4	4		36	36		59	59		22	22
			63 - Total Gross Utility Plant								5,007	5,007		6,009	6,009
		1880 - R&D Expenses	52 - Past 3 Mo MMBTU Burned (Coal)		51	51									
		2440 - Curr. Unreal Losses - NonAffil	39 - 100% to One Company	5,407		5,407									
		2540 - Other Regulatory Liabilities	39 - 100% to One Company	436,932		436,932									
		4261 - Donations	58 - Total Assets		106	106					234	234		234	234
	Southwestern Electric Power Company Total			370	2,647	3,017	129	155	284	1	5,633	5,635	60	6,599	6,658
	Wheeling Power Company	1070 - Construction Work In Progress	39 - 100% to One Company	45,468		45,468	37,215		37,215	4,949		4,949	4,505		4,505
		1080 - Accum Prov for Deprec of Plant	39 - 100% to One Company	737		737	0		0	1,013		1,013	1,013		1,013
		1840 - Clearing Accounts	31 - Number of Vehicles					16	16		35	35		21	21
		4118 - Gain Disposition of Allowances	39 - 100% to One Company				(0)		(0)	(23)		(23)	(23)		(23)
		4210 - Misc Non-Operating Income	39 - 100% to One Company										(6,035)		(6,035)
		4560 - Other Electric Revenues	39 - 100% to One Company	(1,675)		(1,675)									
	Wheeling Power Company Total			44,530		44,530	37,216	16	37,231	5,939	35	5,974	(540)	21	(519)
	Other	1070 - Construction Work In Progress	39 - 100% to One Company							93		93	93		93
			58 - Total Assets					0	0		2	2		2	2
		1520 - Fuel Stock Exp Undistributed	39 - 100% to One Company				1,821		1,821						
		1840 - Clearing Accounts	39 - 100% to One Company	(64,214)		(64,214)									
			61 - Total Fixed Assets		465	465		447	447						
			63 - Total Gross Utility Plant								4	4		4	4

Kentucky Power Company
Other Affiliates Charges by FERC Account, Allocation Factor and Allocation Type
For 2014,2015,2016 and Test Year Ended February 2017

Kentucky Power has a variety of transactions with affiliates on a normal basis. Transactions with affiliates generally fall into two categories. The first category, service payments, is a billing made when an affiliate provides a service to Kentucky Power, such as Appalachian Power providing assistance in distribution maintenance, generation engineering, or other affiliates providing assistance during storm recovery efforts. The second category, convenience payments, occurs when an affiliate company receives an invoice and the cost of that invoice should be borne by multiple AEP companies. For example, a legal invoice for a system-wide issue may be paid by one affiliate company, and that company then bills the other affiliates who benefit from the service.

Charges from affiliates are accumulated using a work order system. All affiliate services and convenience payments are billed to Kentucky Power at cost, per FERC affiliate requirements.

				2014			2015			2016			TEST YEAR		
Account Type	Affiliate	FERC Account	Allocation Factor	Direct	Allocated	Total	Direct	Allocated	Total	Direct	Allocated	Total	Direct	Allocated	Total
		1880 - R&D Expenses	28 - Number of Trans Pole Miles		19	19									
			61 - Total Fixed Assets								636	636		688	688
		2360 - Taxes Accrued	39 - 100% to One Company	40		40									
	Other Total			(64,174)	484	(63,690)	1,821	447	2,268	93	643	736	93	693	787
Non-Cost of Service				5,924,941	12,017	5,936,957	2,731,663	22,933	2,754,597	1,626,424	69,333	1,695,757	1,629,726	81,014	1,710,740
Grand Total				11,415,844	333,595	11,749,438	7,422,885	337,887	7,760,772	4,922,291	427,091	5,349,382	4,826,759	460,620	5,287,379

Kentucky Power Company
Other Affiliate Charges Billed to Co-Owner by Kentucky Power
For 2014,2015,2016 and Test Year Ended February 2017

		2014			2015			2016			TEST YEAR		
Account Type	FERC Account	Other Affiliates Billed to Kentucky Power	Share Billed to Co-Owner	Total	Other Affiliates Billed to Kentucky Power	Share Billed to Co-Owner	Total	Other Affiliates Billed to Kentucky Power	Share Billed to Co-Owner	Total	Other Affiliates Billed to Kentucky Power	Share Billed to Co-Owner	Total
Cost of Serviice	5000 - Oper Supervision & Engineering	9,780	1,686	11,466	22,338	(11,065)	11,272	30,223	(14,304)	15,919	31,804	(14,659)	17,145
	5010 - Fuel	22,337	(6,443)	15,894	6,647		6,647	5,897		5,897	-		-
	5020 - Steam Expenses	(17,699)	1,890	(15,809)			-			-			-
	5050 - Electric Expenses	793		793			-			-			-
	5060 - Misc Steam Power Expenses	191,747	(64,734)	127,013	18,317	(3,239)	15,078	15,693	(4,279)	11,414	15,510	(4,211)	11,299
	5100 - Maint Supv & Engineering	172,034	79	172,113	163,197	(50)	163,147	143,933	(124)	143,810	123,142	(124)	123,018
	5110 - Maintenance of Structures	17,776	(8,054)	9,722	1,158		1,158	3,790	(1,553)	2,237	(68)	376	308
	5120 - Maintenance of Boiler Plant	(32,862)	53,851	20,988	13,965	(4,705)	9,261	13,241	(1,353)	11,889	14,248	(1,277)	12,971
	5130 - Maintenance of Electric Plant	31,045	(3,397)	27,648	(544)	273	(271)	3,216	(635)	2,581	2,707	(380)	2,327
	5140 - Maintenance of Misc Steam Plt	(10,772)	6,800	(3,972)	15,862		15,862	11,760		11,760	1,530		1,530
	5390 - Misc Hydr Power Generation Exp	69		69			-			-			-
	5570 - Other Expenses	47,586		47,586	61,736		61,736	65,411		65,411	65,648		65,648
	5600 - Oper Supervision & Engineering	34,077		34,077	29,792		29,792	18,242		18,242	24,473		24,473
	5612 - Load Dispatch-Mntr&Op TransSys	61		61			-			-			-
	5620 - Station Expenses	96,910		96,910	216		216	11		11	11		11
	5630 - Overhead Line Expenses			-	1		1	28		28	39		39
	5660 - Misc Transmission Expenses	44,079		44,079	18,804		18,804	44,075		44,075	45,219		45,219
	5680 - Maint Supv & Engineering			-	74		74	3		3	3		3
	5690 - Maintenance of Structures	6,403		6,403			-			-			-
	5692 - Maint of Computer Software			-	32		32	56		56	56		56
	5700 - Maint of Station Equipment	80,817		80,817	17,330		17,330	7,205		7,205	15,163		15,163
	5710 - Maintenance of Overhead Lines	2,167,984		2,167,984	1,338,308		1,338,308	995,069		995,069	922,849		922,849
	5730 - Maint of Misc Trnsmssion Plt	3,319		3,319	2,706		2,706	65		65	642		642
	5800 - Oper Supervision & Engineering	113,778		113,778	102,219		102,219	138,433		138,433	130,074		130,074
	5810 - Load Dispatching	11		11			-			-			-
	5820 - Station Expenses	161,882		161,882	1		1			-			-
	5830 - Overhead Line Expenses	(134)		(134)	166		166	567		567	542		542
	5840 - Underground Line Expenses	3,323		3,323	2,853		2,853	3,049		3,049	2,890		2,890
	5850 - Street Lighting & Signal Sys E	269		269			-			-			-
	5860 - Meter Expenses	63,747		63,747	62,562		62,562	87,152		87,152	86,344		86,344
	5870 - Customer Installations Exp	573		573			-	336		336	336		336
	5880 - Miscellaneous Distribution Exp	89,327		89,327	112,799		112,799	64,884		64,884	64,156		64,156
	5890 - Rents	122		122	142		142	95		95	109		109
	5910 - Maintenance of Structures	13,328		13,328	23		23			-			-
	5920 - Maint of Station Equipment	358,702		358,702	22,318		22,318	35,946		35,946	33,482		33,482
	5930 - Maintenance of Overhead Lines	278,726		278,726	780,092		780,092	175,270		175,270	29,364		29,364
	5940 - Maint of Underground Lines	(74)		(74)	(16)		(16)	97		97	40		40
	5950 - Maint of Lne Trnf,Rglators&Dvi	84		84	51		51	24		24	118		118
	5960 - Maint of Strt Lghtng & Sgnal S			-			-	263		263	263		263
	5970 - Maintenance of Meters	15,661		15,661	1,434		1,434	226		226	226		226
	5980 - Maint of Misc Distribution Plt	2,767		2,767	47		47	40		40	12		12
	9010 - Supervision - Customer Accts	728		728	95		95	72		72	72		72
	9020 - Meter Reading Expenses	700		700	76		76			-			-
	9030 - Cust Records & Collection Exp	7,391		7,391	38,039		38,039	63,698		63,698	69,036		69,036
	9040 - Uncollectible Accounts			-			-	53		53	53		53
	9070 - Supervision - Customer Service	158		158	751		751	188		188	173		173
	9080 - Customer Assistance Expenses	7,460		7,460	317		317	51		51	39		39
	9110 - Supervision - Sales Expenses			-	457		457	110		110	154		154
	9120 - Demonstrating & Selling Exp	137		137	86		86	689		689	689		689
	9200 - Administrative & Gen Salaries	876,846	49,175	926,021	732,369	(54,394)	677,975	927,433	(290,706)	636,726	926,604	(291,280)	635,324
	9210 - Office Supplies and Expenses	78,524	12,850	91,374	22,458	12,851	35,309	111,417	(41,319)	70,098	129,563	(48,486)	81,077
	9230 - Outside Services Employed	249,502	8,634	258,136	174,756	875	175,631	233,047	(18,646)	214,401	214,686	(20,038)	194,647
	9240 - Property Insurance			-			-	366		366	366		366
	9250 - Injuries and Damages	56,443	(27,186)	29,257	13,563	(3,968)	9,595	10,313	(3,353)	6,960	10,580	(3,468)	7,112
	9260 - Employee Pensions & Benefits	27	(6)	21	37	(11)	25	94	(32)	62	94	(32)	62
	9280 - Regulatory Commission Exp	206,595	(39,764)	166,831	914,609	(192,036)	722,574	102,823		102,823	274,855		274,855
	9301 - General Advertising Expenses	20,229	(4,362)	15,867	18,001	(2,683)	15,318	34,373		34,373	33,143		33,143
	9302 - Misc General Expenses	137,512	(11,949)	125,563	110,922	(12,961)	97,961	148,825	(19,326)	129,499	148,951	(22,456)	126,495
	9310 - Rents	17,568		17,568	19,114		19,114	18,864		18,864	18,841		18,841
	9350 - Maintenance of General Plant	101,482	(16,907)	84,575	100,368	(30,487)	69,881	94,928	(25,681)	69,247	93,337	(22,408)	70,929
	9090 - Information & Instruct Advrtis	53,190		53,190	32,471		32,471	22,076		22,076	23,756		23,756
	9100 - Misc Cust Svc&Informational Ex	30,415		30,415	33,058		33,058	19,907		19,907	20,717		20,717
Cost of Service Total		5,812,481	(47,837)	5,764,644	5,006,176	(301,601)	4,704,575	3,653,625	(421,310)	3,232,315	3,576,639	(428,443)	3,148,196
Non-Cost of Service	1070 - Construction Work In Progress	2,437,334	(82,335)	2,354,999	2,264,826	(139,888)	2,124,938	1,239,254	(8,755)	1,230,500	1,269,444	(10,013)	1,259,431
	1080 - Accum Prov for Deprec of Plant	(2,952,564)	10,205	(2,942,360)	48,560	(1,631)	46,930	18,895	(506)	18,388	9,620	(506)	9,114
	1430 - Other Accounts Receivable	(0)		(0)			-			-			-
	1510 - Fuel Stock	(972,003)		(972,003)			-			-			-
	1520 - Fuel Stock Exp Undistributed	(109,119)		(109,119)	1,821		1,821	5,395		5,395	3,232		3,232
	1540 - Materials & Oper Supplies	98,016		98,016	2,074		2,074			-			-
	1650 - Prepayments	117,441		117,441			-			-			-
	1740 - Misc Current & Accrued Assets			-	(4)		(4)			-			-
	1750 - Curr. Unreal Gains - NonAffil	(631,845)		(631,845)			-			-			-
	1830 - Prelimin Surv&Investgtn Chrgs	(5,079)		(5,079)			-	7		7	7		7
	1840 - Clearing Accounts	(13,528)		(13,528)	36,113		36,113	69,412		69,412	79,275		79,275
	1850 - Temporary Facilities			-	55		55			-			-
	1860 - MDD-Internal Billing Only	14,267		14,267	24,389		24,389	53,694		53,694	55,381		55,381
	1880 - R&D Expenses	200,347		200,347	200,645		200,645	1,521		1,521	1,391		1,391
	2300 - Asset Retirement Obligations	79,484		79,484			-			-			-
	2360 - Taxes Accrued	40		40			-			-			-
	2440 - Curr. Unreal Losses - NonAffil	5,407		5,407			-			-			-
	2540 - Other Regulatory Liabilities	4,157,054		4,157,054			-			-			-
	4030 - Depreciation Expense	2,849,955		2,849,955			-			-			-
	4031 - Depreciation Expense for Asset Retirement Costs	134,664		134,664			-			-			-
	4111 - Prov Def I/T-Cr Util Oper Inc	(79,484)	39,742	(39,742)			-			-			-
	4118 - Gain Disposition of Allowances			-	(0)		(0)	(23)	11	(11)	(23)	11	(11)
	4210 - Misc Non-Operating Income			-			-	(901)		(901)	(6,937)	3,018	(3,919)
	4261 - Donations	188,048	(40,314)	147,734	17,654	(1,532)	16,121	27,000		27,000	17,910		17,910
	4265 - Other Deductions	177,347	(37,996)	139,351	31,403	(9,146)	22,257	43,767	(14,975)	28,792	21,668	(7,476)	14,192
	4540 - Rent From Electric Property	(12,897)		(12,897)	(12,897)		(12,897)	(12,897)		(12,897)	(12,897)		(12,897)
	4560 - Other Electric Revenues	(93,591)		(93,591)	(136,025)		(136,025)	(98,268)		(98,268)	(97,514)		(97,514)
	4264 - Civic & Political Activities	85,650	(18,425)	67,225	107,726	(17,450)	90,276	152,602		152,602	163,460		163,460
	4310 - Other Interest Expense	262,013	(56,278)	205,735	168,255	(22,608)	145,648	196,301		196,301	206,723		206,723
	4081 - Taxes Other Than Inc Tax, UOI			-			-	(0)		(0)	(0)		(0)
Non-Cost of Service Total		5,936,957	(185,402)	5,751,555	2,754,597	(192,255)	2,562,342	1,695,757	(24,224)	1,671,533	1,710,740	(14,967)	1,695,774
Grand Total		11,749,438	(233,240)	11,516,198	7,760,772	(493,856)	7,266,916	5,349,382	(445,534)	4,903,848	5,287,379	(443,409)	4,843,970

RATE SCHEDULE NO. 303

MITCHELL PLANT OPERATING AGREEMENT

KENTUCKY POWER COMPANY

WHEELING POWER COMPANY

and

AMERICAN ELECTRIC POWER SERVICE CORPORATION, AS AGENT

Tariff Submitter: **Kentucky Power Company**
FERC Program Name: **FERC FPA Electric Tariff**
Tariff Title: **KPCo Rate Schedules and Service Agreement Tariffs**
Tariff Proposed Effective Date: **12/31/2014**
Tariff Record Title: **Mitchell Plant Operating Agreement**
Option Code: **A**
Record Content Description: **Rate Schedule No. 303**

THIS MITCHELL PLANT OPERATING AGREEMENT ("Agreement"), with an effective date of December 31, 2014 ("Effective Date"), is by and among Kentucky Power Company, a Kentucky corporation qualified as a foreign corporation in West Virginia ("KPCo"), and Wheeling Power Company, a West Virginia corporation ("WPCo") (such two parties hereinafter sometimes referred to as the "Owners"); and American Electric Power Service Corporation, a New York corporation qualified as a foreign corporation in West Virginia ("Agent"). KPCo, WPCo and Agent may hereinafter be referred to as a "Party" or collectively as the "Parties".

WITNESSETH:

WHEREAS, KPCo acquired a fifty percent (50%) undivided ownership interest in the Mitchell Power Generation Facility consisting of two 800MW generating units and associated plant, equipment and real estate, located in Moundsville, West Virginia (the "Mitchell Facility") on December 31, 2013; and

WHEREAS, AEP Generation Resources Inc. ("AEPGR"), an affiliate of the Parties, acquired a fifty percent (50%) undivided ownership interest in the Mitchell Facility, also on December 31, 2013; and

WHEREAS, pursuant to an Asset Contribution Agreement between AEPGR and Newco Wheeling Inc., a West Virginia corporation merged or to be merged into WPCo upon the closing of the transactions (the "Transfer Date") set forth in such Asset Contribution Agreement (the "ACA"), AEPGR transferred its fifty percent (50%) undivided interest in the Mitchell Facility to Newco Wheeling Inc., exclusive of its interest in the Conner Run Fly Ash Impoundment and Dam ("Conner Run"), which interest in Conner Run was retained on the Transfer Date by AEPGR; and

WHEREAS, this Agreement shall be effective upon the Effective Date but the rights and obligations set forth herein shall not commence until 12:01 AM on the day following the Transfer Date; and

WHEREAS, the Owners desire that KPCo shall operate and maintain the Mitchell Facility, exclusive of Conner Run (the "Mitchell Plant"), in accordance with the provisions set forth herein; and

WHEREAS, the Owners are subsidiaries of American Electric Power Company, Inc. ("AEP"), the parent company in an integrated public utility holding company system, and use the services of Agent (an affiliated company engaged solely in the business of furnishing essential services to the Owners and to other affiliated companies), as outlined in the service agreements between Agent and KPCo and between Agent and WPCo.

NOW THEREFORE, in consideration of the premises and for the purposes hereinabove recited, and in consideration of the mutual covenants hereinafter contained, the signatories agree as follows:

ARTICLE ONE

FUNCTIONS OF KPCO AND AGENT

1.1 KPCo shall operate and maintain the Mitchell Plant in accordance with good utility practice consistent with procedures employed by KPCo at its other generating stations, and in conformity with the terms and conditions of this Agreement.

1.2 KPCo shall keep all necessary books of record, books of account and memoranda of all transactions involving the Mitchell Plant, and shall make computations and allocations on behalf of the Owners, as required under this Agreement. The books of record, books of account and memoranda shall be kept in such manner as to conform, where so required, to the Uniform System of Accounts as prescribed by the Federal Energy Regulatory Commission ("FERC") for Public Utilities and Licensees ("Uniform System of Accounts"), and to the rules and regulations of other regulatory bodies having jurisdiction as they may from time to time be in effect.

1.3 The Owners shall establish such bank accounts as may from time to time be required or appropriate.

1.4 As soon as practicable after the end of the month, KPCo shall furnish to WPCo a statement setting forth the dollar amounts associated with the operation and maintenance of the Mitchell Plant as allocated hereunder to KPCo and WPCo for such month. The Owners shall, on a timely basis, deposit sufficient dollar amounts in the appropriate bank accounts to cover their respective allocations of such costs.

1.5 KPCo shall be responsible for the day to day operation and maintenance of the Mitchell Plant. KPCo shall obtain such materials, labor and other services as it considers necessary in connection with the performance of the functions to be performed by it hereunder from such sources or through such persons as it may designate.

1.6 Agent, as directed by the Operating Committee and consistent with Agent's service agreements with KPCo and WPCo, shall provide services necessary for the safe and efficient operation and maintenance of the Mitchell Plant.

ARTICLE TWO

APPORTIONMENT OF CAPACITY AND ENERGY

2.1 The Total Net Capability of the Mitchell Plant at the Mitchell Unit 1 and Unit 2 low-voltage busses, after taking into account auxiliary load demand, is 1,560,000 kilowatts. The Owners may from time to time modify the Total Net Capability of the Mitchell Plant as they may mutually agree.

2.2 The Total Net Generation of the Mitchell Plant during a given period, as determined by the requirements of KPCo and WPCo, shall mean the electrical output of the Mitchell Plant generators during such period, measured in kilowatt hours by suitable instruments, reduced by the energy used by auxiliaries for the Mitchell Unit 1 and Unit 2 during such period.

2.3 Except as set forth in Section 7.6 (including Section 7.6 Subsections), in any hour, KPCo and WPCo shall share the minimum load responsibility of Mitchell Unit 1 and Unit 2 in respective amounts proportionate to their ownership interests in the Mitchell Plant at such time. Each Owner may independently dispatch its share of the generating capacity between minimum and full load.

2.4 In any hour during which the Mitchell Units are out of service, the energy used by the out-of-service Units' auxiliaries during such hour shall be provided by KPCo and WPCo in respective amounts proportionate to their ownership interests in the Mitchell Plant at such time.

ARTICLE THREE

REPLACEMENTS, ADDITIONS, AND RETIREMENTS

3.1 KPCo shall from time to time make or cause to be made any additions to, replacements of, and retirements of, capitalizable facilities associated with the Mitchell Plant in accordance with the approved annual budget.

3.2 The dollar amounts associated with any additions to, replacements of, or retirements of, capitalizable facilities associated with the Mitchell Plant shall be allocated to KPCo and WPCo in respective amounts proportionate to their ownership interests in the Mitchell Plant at the time such additions, replacements, or retirements are made.

ARTICLE FOUR

WORKING CAPITAL REQUIREMENTS

4.1 KPCo and WPCo shall periodically mutually determine the amount of funds required for use as working capital in meeting payrolls and other expenses incurred in the operation and maintenance of the Mitchell Plant, and in buying materials and supplies (exclusive of fuel) for the Mitchell Plant.

4.2 KPCo and WPCo shall from time to time provide their share of working capital requirements in respective amounts proportionate to their ownership interests at such time in the Mitchell Plant.

ARTICLE FIVE

INVESTMENT IN FUEL

5.1 KPCo and Agent shall establish and maintain reserves of coal in stock piles for the Mitchell Plant of such quality and in such quantities as the Operating Committee shall determine to be required to provide adequate fuel reserves against interruptions of normal fuel supply, provided each Owner, subject to the approval of the Operating Committee and subject to no adverse impact on the operation of the Mitchell Plant, will have the right, but not the obligation, to directly purchase coal, transportation and consumables for its ownership interest. For the purposes of this Agreement, "consumables" shall be as defined in FERC account 502.

5.2 Except as provided in Section 5.1 for an Owner to elect to procure coal for its own interest, the Owners shall make such monthly investments in the common coal stock piles associated with the Mitchell Plant as are necessary to maintain the number of tons in such coal stock piles, after taking into account the coal consumption from the common coal stock piles by Mitchell Unit 1 and Unit 2 during such month.

5.3 At any time, KPCo's and WPCo's respective shares of the investment in the common coal stock piles shall be proportionate to their ownership interests in the Mitchell Plant, unless an Owner elects to procure its own coal as provided in Section 5.1, in which case inventories will be separately maintained for accounting purposes.

5.4 Fuel oil and consumables charged to operation for the Mitchell Plant shall be owned and accounted for between the Owners in the same manner as coal.

ARTICLE SIX

APPORTIONMENT OF STATION COSTS

6.1 Except in the case where an Owner has elected to purchase coal for its own interest as provided for in Section 5.1 (in which case the allocation to the Owners of fuel expense shall be in accordance with procedures and processes approved by the Operating Committee), the allocation to the Owners of fuel expense associated with Mitchell Unit 1 and Unit 2 shall be determined by KPCo and Agent as follows:

(a) In any calendar month, the average unit cost of coal available for consumption from the Mitchell Plant common coal stock piles shall be determined based on the prior month's ending inventory dollar and ton balances plus current month receipts delivered to the Mitchell Plant common coal stock piles. Each Owner's average unit cost will be the same, and receipts and inventory available for consumption amounts will be allocated to each Owner based on monthly usage.

(b) The number of tons of coal consumed by the Mitchell Plant in each calendar month from the Mitchell Plant common coal stock piles shall be determined and shall be converted into a dollar amount equal to the product of (i) the average cost per ton of coal associated with the Mitchell Plant in the Mitchell Plant common coal stock pile at the close of such month, and (ii) the number of tons of coal consumed by the Mitchell Plant from the Mitchell Plant common coal stock piles during such month. Such dollar amount shall be credited to the

Mitchell Plant fuel in stock pile and charged to Mitchell Plant fuel consumed.

(c) In each calendar month, KPCo's and WPCo's respective shares of the Mitchell Plant fuel consumed expense as determined by the provisions of Section 6.1(b) shall be proportionate to each Owner's dispatch of the Mitchell Plant in such month.

(d) Fuel oil reserves will be owned and accounted for in the same manner as coal stock piles, and fuel oil consumed will be allocated to the Owners in the same manner as coal consumed.

6.2 For purposes of this Agreement, KPCo's Assigned Capacity in the Mitchell Plant shall be equal to 50% of the Total Net Capability, and WPCo's Assigned Capacity shall be equal to 50% of the Total Net Capability.

6.3 For each calendar month, KPCo and Agent will, to the extent practicable, determine all Mitchell Plant operations expenses and associated overheads, as accounted for under the FERC Uniform System of Accounts.

6.4 For each calendar month, KPCo and Agent will, to the extent practicable, determine all Mitchell Plant maintenance expenses and associated overheads, as accounted for under the FERC Uniform System of Accounts.

6.5 In each calendar month, KPCo's and WPCo's respective shares of operations and maintenance expenses associated with the Mitchell Plant, as determined in accordance with Sections 6.3 and 6.4, shall be allocated as follows:

(a) In each calendar month, KPCo's and WPCo's respective shares of the Mitchell Plant steam expenses as recorded in FERC Account 502, and emission tons, with allowance expenses as recorded in FERC Account 509, shall be proportionate to each Owner's dispatch of the Mitchell Plant in such month.

(b) In each calendar month, the maintenance of boiler plant expenses as recorded in FERC Account 512, and maintenance of electric plant expenses as recorded in FERC Account 513, shall be directly assigned to Mitchell Unit 1 or Unit 2 or designated as a common expense attributable to both units. In each calendar month, KPCo's and WPCo's respective shares of these expenses shall be proportionate to each Owner's dispatch of the applicable unit, or both units in the case of common expenses, over the previous sixty (60) calendar months. Dispatch is assumed to have been allocated fifty percent (50%) to each Owner for months that are prior to this Agreement.

(c) In each calendar month, KPCo's and WPCo's respective shares of all other operations, maintenance, administrative and general expenses shall be proportionate to their respective ownership interests.

6.6 Each Owner shall bear the cost of all taxes attributable to its respective ownership interest in the Mitchell Plant.

ARTICLE SEVEN

OPERATING COMMITTEE AND OPERATIONS

7.1 By written notice to each other, the Owners and Agent each shall name one representative ("Operating Representative") and one alternate to act for it in matters pertaining to operating arrangements under this Agreement. Any Party may change its Operating Representative or alternate at any time by written notice to the other

Parties. The Operating Representatives for the respective Parties, or their alternates, shall comprise the Operating Committee. All decisions, directives, or other actions by the Operating Committee must be by unanimous agreement of the Operating Representatives of the Owners. The Operating Representative of Agent, or of any third party that provides services in replacement of Agent, shall be free to express the views of Agent or such third party on any matter, but shall not have a vote on the Operating Committee. Except as otherwise provided in Sections 11.1, 11.2 and 11.3 with respect to a dispute referred to the Operating Committee by an Owner, the failure of the Owners' respective Operating Representatives to unanimously agree with respect to a matter pending before the Operating Committee shall not be considered to be a dispute that would be subject to resolution under Article Eleven.

7.2 The Operating Committee shall have the following responsibilities:

(a) Review and approval of an annual budget and annual operating plan, including determination of the emission allowances required to be acquired by KPCo and WPCo. If the Operating Committee fails to approve an annual budget, the approved annual budget from the previous year will continue to apply until such time as the new annual budget is approved.

(b) Establishment and review of procedures and systems for dispatch, notification of dispatch, and unit commitment under this Agreement, including any commitment of Called Capacity pursuant to Section 7.6.2.

(c) Establishment and monitoring of procedures for communication and coordination with respect to the Mitchell Plant capacity availability, fuel-firing options, and scheduling of outages for maintenance, repairs, equipment replacements, scheduled inspections, and other foreseeable cause of outages, as well as the return to availability following an unplanned outage.

(d) Decisions on capital expenditures, including unit upgrades and re-powering.

(e) Determinations as to changes in the unit capability and decisions on unit retirement.

(f) Establishment and modification of billing procedures under this Agreement.

(g) Approval of material contracts for fuel, transportation or consumable supply. Establishment of specification of fuels, oversight of fuel inspection and certification procedures, management of fuel inventories, and allocation of rights under fuel supply, transportation and consumable contracts. Establishment of an Owner's procurement rights and procedures if the Owner elects to purchase coal, transportation or consumables for its own interest.

(h) Establishment of, termination of, and approval of any change or amendment to the operating arrangements between KPCo and Agent or any replacement third party with respect to the Mitchell Plant generating units; provided, however, that Agent or any replacement third party shall participate in discussions pursuant to this subsection 7.2(h) only if and to the extent requested to do so by both Owners.

(i) Review and approval of plans and procedures designed to ensure compliance with any environmental law, regulation, ordinance or permit, including procedures for allocating and using emission allowances or for any programs that permit averaging at more than one unit for compliance.

(j) Other duties as assigned by agreement of the Owners.

7.3 The Operating Committee shall meet at least annually, and at such other times as any Party may reasonably request.

7.4 The Parties shall cooperate in providing to the Operating Committee the information it reasonably needs to carry out its duties, and to supplement or correct such information on a timely basis.

7.5 The Owners will each make an initial unit commitment one business day ahead of real-time dispatch.

7.6 Application of this Section 7.6 (including subsections) is subject to (i) the receipt of any necessary regulatory approvals or waivers expressly granted for this Section 7.6; and (ii) the Operating Committee establishing and approving procedures and systems for dispatch. As used in this Section and subsections of this Section, the terms "Party" or "Parties" refers only to KPCo and WPCo, or both of them, as the case may be.

7.6.1 If Mitchell Unit 1 or Unit 2 is designated to be committed by both Parties, such unit will be brought on line or kept on line. If neither Party designates Mitchell Unit 1 or Unit 2 to be committed, such unit will remain off line or be taken offline.

7.6.2 When a Mitchell Unit is designated to be committed by one Party, but designated not to be committed by the other Party, the unit will be brought on line or kept on line if the Party designating the unit for commitment undertakes to pay any applicable start-up costs for the unit, as well as any applicable minimum running costs for the unit thereafter, in which event the unit shall be brought on line or kept on line, as the case may be. The Party so designating the unit to be committed shall have the right to schedule and dispatch up to all of the Available Capacity of the unit. Available Capacity means that portion of the Owners' aggregate Assigned Capacity that is currently capable of being dispatched. The Party exercising this right shall be referred to as the "Calling Party," and the capacity called by that Party in excess of its Assigned Capacity Percentage of the Available Capacity of that unit shall be referred to as its "Called Capacity." The other Party shall be referred to as the "Non-Calling Party". The Calling Party shall provide reasonable notice to the Non-Calling Party of its call, including any start-up or shut-down time for the Unit. For purposes of this Agreement, KPCo's Assigned Capacity Percentage shall be 50%, and WPCo's Assigned Capacity Percentage shall be 50%.

7.6.3 The Non-Calling Party can reclaim any Called Capacity attributable to its Assigned Capacity share by giving the Calling Party notice equal to the normal cold start-up time for the unit. At the end of the notice period, the Non-Calling Party shall have the right to schedule and dispatch the recalled capacity. At that point, the Non-

Calling Party shall resume its responsibility for its share of any applicable start-up costs for the unit and prospectively shall bear its responsibility for the costs associated with its Assigned Capacity from the unit.

7.6.4 If any capacity remains available but is not dispatched from a Party's Available Capacity committed as a result of the initial unit commitment, the other Party may only schedule and dispatch such capacity pursuant to agreement with the non-dispatching Party.

7.7 KPCo and WPCo shall be individually responsible for any fees charged by FERC on the basis of the sales or transmission by each of capacity or energy at wholesale in interstate commerce.

7.8 Emission Allowances. On the Transfer Date pursuant to the ACA, AEPGR, the previous owner of WPCo's interest in the Mitchell Plant, will assign to WPCo all Emission Allowances allocated to AEPGR for the Mitchell Plant for each vintage year after 2014, issued by the U.S. Environmental Protection Agency ("USEPA") pursuant to Title IV of the Clean Air Act Amendments of 1990 and any regulations thereunder, and any other emission allowance trading program created under the Clean Air Act and administered by USEPA or the State of West Virginia, including but not limited to the Clean Air Interstate Rule 40 CFR Parts 96 and 97, and any amendments thereto ("Emission Allowances"), and all Emission Allowances for 2014 and any vintage year prior to 2014 that were allocated to the Mitchell Plant and that have not been expended as of the date of assignment. To the extent that additional Emission Allowances are required for operation of the Mitchell Plant, KPCo and WPCo will each be responsible for acquiring sufficient Emission

Allowances to satisfy the Emission Allowances required because of its dispatch of energy from the Mitchell Plant, and the Emission Allowances required to satisfy the Emission Allowance surrender obligations attributable to the Mitchell Plant imposed under the Consent Decree between USEPA and Ohio Power Company entered on December 10, 2007, in Civil Action No. C2-99-1182 and consolidated cases by the U.S. District Court in the Southern District of Ohio. On or before January 10 of each year, Agent shall determine and notify KPCo and WPCo of the number of additional annual Emission Allowances consumed by each of them through December 31 of the previous year, and KPCo and WPCo shall each transfer into the Mitchell Plant U.S. EPA Allowance Transfer System account that number of Emission Allowances with a small compliance margin by January 31 of that year. For seasonal Emission Allowance programs, Agent shall determine and notify KPCo and WPCo of the number of additional seasonal Emission Allowances consumed by each of them during the applicable compliance period by the 10th day of the first month following the end of the compliance period, and KPCo and WPCo shall each transfer into the appropriate Mitchell Plant U.S. EPA Allowance Transfer System Account that number of Emission Allowances with a small compliance margin by the last day of the first month following the end of the compliance period. In the event that KPCo or WPCo fails to surrender the required number of Emission Allowances by January 31 or the last day of the first month following any seasonal compliance period, Agent shall purchase the required number of Emission Allowances, and KPCo or WPCo, as the case may be, shall reimburse Agent for such purchases, with interest at the Federal Funds Rate (as published by the Board of

Governors of the Federal Reserve System as from time to time in effect) running from the date of such purchases to the date of payment. The Operating Committee will develop procedures to be implemented after the end of each calendar year to account for the Emission Allowances required by the use of the Mitchell Plant by KPCo and WPCo and to correct any imbalance between Emission Allowances supplied and Emission Allowances used through the end of the preceding year by settlement or payment.

7.9 Capital repairs and improvements to the Mitchell Plant will be determined by the Operating Committee pursuant to the annual budgeting process set forth in Section 7.10. Expenditures that the Operating Committee determines have been or will be incurred exclusively for one Owner shall be assigned exclusively to that Owner.

7.10 At least 90 days before the start of each operating year, KPCo and Agent shall submit to the Operating Committee a proposed annual budget with respect to the Mitchell Plant, a proposed annual operating plan, and an estimate and schedule of costs to be incurred for major maintenance or replacement items during the next six-year period. The annual budget shall be presented on a month-by-month basis for each month during the next operating year, and shall include an operating budget, a capital budget, an estimate of the cost of any major repairs that are anticipated will occur during such operating year with respect to the Mitchell Plant, and an itemized estimate of all projected non-fuel variable operating expenses relating to the operation of the Mitchell Plant during that operating year. The members of the Operating Committee will meet and work in good faith to agree upon the final annual budget and final annual operating plan. Once approved, the annual budget and annual operating plan shall remain in effect throughout the applicable operating year, subject to such changes, revisions, amendments, and updating as the Operating Committee may determine.

ARTICLE EIGHT

EFFECTIVE DATE AND TERM

8.1 Subject to FERC approval or acceptance for filing, the Effective Date of this Agreement shall be December 31, 2014.

8.2 Subject to FERC approval or acceptance, if necessary, this Agreement shall remain in force until such time as (i) KPCo or WPCo has divested itself of all or any portion of its ownership interest in the Mitchell Plant, other than assignment or other transfer of such ownership interests to another AEP affiliate; or (ii) either KPCo or WPCo is no longer a direct or indirect wholly owned subsidiary of AEP; or (iii) KPCo and WPCo may mutually agree to terminate this Agreement.

ARTICLE NINE

GENERAL

9.1 This Agreement shall inure to the benefit of and be binding upon the signatories hereto and their respective successors and assigns, but this Agreement may not be assigned by any signatory without the written consent of the others, which consent shall not be unreasonably withheld.

9.2 This Agreement is subject to the regulatory authority of any State or Federal agency having jurisdiction.

9.3 The interpretation and performance of this Agreement shall be in accordance with the laws of the State of Ohio, excluding conflict of laws principles that would require the application of the laws of a different jurisdiction.

9.4 This Agreement supersedes all previous representations, understandings, negotiations, and agreements, either written or oral between the signatories or their representatives with respect to operation of the Mitchell Plant, and constitutes the entire agreement of the signatories with respect to the operation of the Plant. Notwithstanding the foregoing, this Agreement does not supersede any previous agreements among any of the signatories allocating or transferring rights to capacity and associated energy, or ownership, of the Mitchell Plant.

9.5 Each Party shall designate in writing a representative to receive any and all notices required under this Agreement. Notices shall be in writing and shall be given to the representative designated to receive them, either by personal delivery, certified mail, facsimile, e-mail or any similar means, properly addressed to such representative at the address specified below:

KENTUCKY POWER COMPANY
Gregory G. Pauley
President & COO

Attn:

Phone: (502) 696-7007

Facsimile:(502) 696-7006

Email: ggpauley@aep.com

WHEELING POWER COMPANY
Charles R. Patton
President

Attn:

Phone: (304) 348-4152

Facsimile: (304) 348-4198

Email: crpatton@aep.com

AMERICAN ELECTRIC POWER SERVICE CORPORATION
Mark C. McCullough
Executive Vice President – Generation

Attn:

Phone: (614) 716-2400

Facsimile: (614) 716-1331

Email: mcmccullough@aep.com

All notices shall be effective upon receipt, or upon such later date following receipt as set forth in the notice. Any Party may, by written notice to the other Parties, change the representative or the address to which such notices are to be sent.

ARTICLE TEN

LIMITATION OF LIABILITY

10.1 Notwithstanding anything in this Agreement to the contrary, neither of the Owners or Agent shall be liable under this Agreement for special, consequential, indirect, punitive or exemplary damages, or for lost profits or business interruption damages, whether arising by statute, in tort or contract or otherwise.

ARTICLE ELEVEN

DISPUTE RESOLUTION

11.1 If either Owner believes that a dispute has arisen as to the meaning or application of this Agreement, it shall present that matter to the Operating Committee in writing, and shall provide a copy of that writing to the other Owner.

11.2 If the Operating Committee is unable to reach agreement on a dispute submitted to the Operating Committee pursuant to Section 11.1within thirty (30) days after the dispute is presented to it, the matter shall be referred to the chief operating officers of the Owners for resolution in the manner that such individuals shall agree is appropriate; provided, however, that either Owner involved in the dispute may invoke the arbitration provisions set forth in Section 11.3 at any time after the end of the thirty (30) day period provided for the Operating Committee to reach agreement if the Operating Committee has not reached agreement.

11.3 If the Owners are unable to resolve a dispute through the Operating Committee within thirty (30) days after the dispute is presented to the Operating Committee pursuant to Section 11.1, or through reference of the matter to the chief operating officers of the Owners pursuant to Section 11.2, either Owner may commence arbitration proceedings by providing written notice to the other Owner, detailing the nature of the dispute, designating the issue(s) to be arbitrated, identifying the provisions of this Agreement under which the dispute arose, and setting forth such Owner's proposed resolution of such dispute.

11.3.1 Within ten (10) days of the date of the notice of arbitration, a representative of each Owner shall meet for the purpose of selecting an arbitrator. If the Owners' representatives are unable to agree on an arbitrator within fifteen (15) days of the date of the notice of arbitration, then an arbitrator shall be selected in accordance with the procedures of the American Arbitration Association ("AAA"). Whether the arbitrator is selected by the Owners' representatives or in accordance with the procedures of the AAA, the arbitrator shall have the qualifications and experience in the occupation, profession, or discipline relevant to the subject matter of the dispute.

11.3.2 Any arbitration proceeding shall be subject to the Federal Arbitration Act, 9 U.S.C. §§ 1 *et seq.* (1994), as it may be amended, or any successor enactment thereto, and shall be conducted in accordance with the commercial arbitration rules of the AAA in effect on the date of the notice to the extent not inconsistent with the provisions of this Article.

11.3.3 The arbitrator shall be bound by the provisions of this Agreement where applicable, and shall have no authority to modify any terms and conditions of this Agreement in any manner. The arbitrator shall render a decision resolving the dispute in an equitable manner, and may determine that monetary damages are due to an Owner or may issue a directive that an Owner take certain actions or refrain from taking certain actions, but shall not be authorized to order any other form of relief; provided, however, that nothing in this Article shall preclude the arbitrator from rendering a decision that adopts the resolution of the dispute proposed by an Owner. Unless otherwise agreed to by the Owners, the arbitrator shall render a decision within one hundred twenty (120) days of appointment, and shall notify the Owners in writing of such decision and the reasons supporting such decision. The decision of the arbitrator shall be final and binding upon the Owners, and any award may be enforced in any court of competent jurisdiction.

11.3.4 The fees and expenses of the arbitrator shall be shared equally by the Owners, unless the arbitrator specifies a different allocation. All other expenses and costs of the arbitration proceeding shall be the responsibility of the Owner incurring such expenses and costs.

11.3.5 Unless otherwise agreed by the Owners, any arbitration proceedings shall be conducted in Columbus, Ohio.

11.3.6 Except as provided in this Article, the existence, contents, or results of any arbitration proceeding under this Article may not be disclosed without the prior written consent of the Owners, provided, however, that either Owner may make disclosures as may be required to fulfill regulatory obligations to any agencies having jurisdiction, and may inform its lenders, affiliates, auditors, and insurers, as necessary, under pledge of confidentiality, and may consult with expert consultants as required in connection with an arbitration proceeding under pledge of confidentiality.

11.3.7 Nothing in this Agreement shall be construed to preclude either Owner from filing a petition or complaint with FERC with respect to any claim over which FERC has jurisdiction. In such case, the other Owner may request that FERC reject the petition or complaint or otherwise decline to exercise its jurisdiction. If FERC declines to act with respect to all or part of a claim, the portion of the claim not so accepted by FERC may be resolved through arbitration, as provided in this Article. To the extent that FERC asserts or accepts jurisdiction over all or part of a claim, the decisions, findings of fact, or orders of FERC shall be final and binding, subject to judicial review under the Federal Power Act, 16 U.S.C. § 791a *et seq.,* as amended from time to time, and any arbitration proceedings that may have commenced prior to the assertion or acceptance of jurisdiction by FERC shall be stayed, pending the outcome of the FERC proceedings. The arbitrator shall have no authority to modify, and shall be conclusively bound by, any decisions, findings of fact, or orders of FERC; provided, however, that to the extent that any decisions, findings of fact, or orders of FERC do not provide a final or complete remedy to an Owner seeking relief, such Owner may proceed to arbitration under this Article to secure such a remedy, subject to any FERC decisions, findings, or orders.

11.4 The procedures set forth in this Article shall be the exclusive means for resolving disputes arising under this Agreement and shall survive this Agreement to the extent necessary to resolve any disputes pertaining to this Agreement. Except as provided in Sections 11.3 and 11.3.7, neither Owner shall have the right to bring any dispute for resolution before a court, agency, or other entity having jurisdiction over this Agreement, unless both Owners agree in writing to such procedure.

11.5 To the extent that a dispute involves the actions, inactions or responsibilities of Agent under this Agreement, the provisions of this Article shall be applicable to such dispute. For such purposes, Agent shall be treated as an Owner in applying the provisions of this Article.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their officers thereunto duly authorized as of the date first above written.

KENTUCKY POWER COMPANY

By: Greg G Pauley
Gregory G. Pauley

Title: President & COO

WHEELING POWER COMPANY

By:____________________
Charles R. Patton

Title: President

AMERICAN ELECTRIC POWER SERVICE CORPORATION

By:____________________
Mark C. McCullough

Title: Executive Vice President - Generation

11.5 To the extent that a dispute involves the actions, inactions or responsibilities of Agent under this Agreement, the provisions of this Article shall be applicable to such dispute. For such purposes, Agent shall be treated as an Owner in applying the provisions of this Article.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their officers thereunto duly authorized as of the date first above written.

KENTUCKY POWER COMPANY

By:____________________________
Gregory G. Pauley

Title: President & COO

WHEELING POWER COMPANY

By: Charles R. Patton
Charles R. Patton

Title: President

AMERICAN ELECTRIC POWER SERVICE CORPORATION

By:____________________________
Mark C. McCullough

Title: Executive Vice President - Generation

11.5 To the extent that a dispute involves the actions, inactions or responsibilities of Agent under this Agreement, the provisions of this Article shall be applicable to such dispute. For such purposes, Agent shall be treated as an Owner in applying the provisions of this Article.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their officers thereunto duly authorized as of the date first above written.

KENTUCKY POWER COMPANY

By:____________________________
Gregory G. Pauley

Title: President & COO

WHEELING POWER COMPANY

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Charles R. Patton

Title: President

AMERICAN ELECTRIC POWER SERVICE CORPORATION

By:____________________________
Mark C. McCullough

Title: Executive Vice President - Generation

Kentucky Power Company
Capital Construction Budget
Years 2017-2019

Category ($000's)	2017	2018	2019
Environmental Generation	14,666	23,279	47,362
Fossil/Hydro Generation	3,713	24,953	30,577
Distribution	35,783	41,391	39,818
Transmission*	21,034	23,007	26,563
Corporate/Other	11,984	10,088	9,198
	87,180	**122,716**	**153,519**

* The Company is currently evaluating its budgeted level of transmission spending as reflected in its most recent capital construction budget.