THIS FILING IS	
Item 1: [X] An Initial (Original) Submission	OR [ ] Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2016)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2016)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2016)

RECEIVED
MAY 02 2016
PUBLIC SERVICE COMMISSION

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Kentucky Power Company	End of 2015/Q4

FERC FORM No.1/3-Q (REV. 02-04)

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/eforms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of ___________ , we have also reviewed schedules ___________________ of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/eforms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/eforms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,144 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 150 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Kentucky Power Company	02 Year/Period of Report End of 2015/Q4
03 Previous Name and Date of Change *(if name changed during year)*	/ /
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 1 Riverside Plaza, Columbus, OH 43215-2373	
05 Name of Contact Person Jason M. Johnson	06 Title of Contact Person Accountant
07 Address of Contact Person *(Street, City, State, Zip Code)* AEP Service Corp., 1 Riverside Plaza, Columbus, OH 43215-2373	

08 Telephone of Contact Person, *Including Area Code* (614) 716-1000	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* / /

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name F. Scott Travis 02 Title Assistant Controller	03 Signature F. Scott Travis	04 Date Signed *(Mo, Da, Yr)* 04/08/2016

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	NA
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	Page 116 - NA
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	NA
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	NA
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	NA
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	NA
25	Unrecovered Plant and Regulatory Study Costs	230	NA
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	NA
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [X] Two copies will be submitted [ ] No annual report to stockholders is prepared		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

F. Scott Travis, Assistant Controller
1 Riverside Plaza
Columbus, OH 43215

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Kentucky
July 21, 1919

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

None

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Electric - Kentucky

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [X] No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

American Electric Power Company, Inc.
Ownership of 100% of Respondent's Common Stock

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	See Footnote		
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
42			
43			
44			

Schedule Page: 104 Line No.: 1 Column: a

Executive Compensation Table

The following table provides summary information concerning compensation paid to or accrued by us on behalf of our Chief Executive Officer, our Chief Financial Officer and the three other most highly compensated executive officers, to whom we refer collectively as the named executive officers.

Name and Principal Position (a)	Salary ($)(1) (b)	Bonus ($) (c)	Stock Awards ($)(2) (d)	Non-Equity Incentive Plan Compensation ($)(3) (f)	Change in Pension Value and Non-qualified Deferred Compensation Earnings ($)(4) (g)	All Other Compensation Earnings ($)(5) (h)	Total ($) (i)
Nicholas K. Akins — Chairman of the Board and Chief Executive Officer	1,279,900	—	6,719,981	3,150,000	199,027	103,658	11,452,566
Brian X. Tierney — Executive Vice President and Chief Financial Officer	709,246	—	1,907,216	1,100,000	0	84,125	3,800,587
Robert P. Powers — Executive Vice President and Chief Operating Officer	709,246	—	1,888,008	1,075,000	0	90,234	3,762,488
David M. Feinberg — Executive Vice President and General Counsel	591,426	—	998,394	800,000	59,069	68,163	2,517,052
Charles E. Zebula — Executive Vice President-Energy Supply	446,310	—	1,496,037	570,000	51,420	54,279	2,618,046

(1) Amounts in the salary column are composed of executive salaries earned for the year shown, which include 261 days of pay for 2015. This is one day more than the standard 260 calendar work days and holidays in a year.

(2) The amounts reported in this column reflect the aggregate grant date fair value, calculated in accordance with FASB ASC Topic 718, of performance units and RSUs granted under our Long-Term Incentive Plan. See Note 15 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2015 for a discussion of the relevant assumptions used in calculating these amounts. With respect to the performance units, the estimates of the grant date fair values determined in accordance with FASB ASC Topic 718 assumes the vesting of 100% of the performance units awarded. The value realized for the performance units, if any, will depend on the Company's performance during a three-year performance and vesting period. The potential payout can range from 0 percent to 200 percent of the target number of performance units, plus any dividend equivalents. Therefore, the maximum amount payable for the 2015 performance units is equal to $9,407,974 for Mr. Akins; $2,670,090 for Mr. Tierney; $2,643,176 for Mr. Powers; $1,397,704 for Mr. Feinberg and $1,254,484 for Mr. Zebula; and the maximum amount payable for the 2014 performance units is equal to $9,408,054 for Mr. Akins, $2,633,798 for Messrs. Powers and Tierney, $1,347,502 for Mr. Feinberg and $1,141,722 for Mr. Zebula. The 2013 performance units vested on December 31, 2015 and are shown in the Option Exercises and Stock Vested for 2015 table. The RSUs vest over a forty month period.

(3) The amounts shown in this column are annual incentive compensation paid under the Senior Officer Incentive Plan for the year shown. At the outset of each year, the HR Committee sets annual incentive targets and performance criteria that are used after year-end to determine if and the extent to which executive officers may receive annual incentive award payments under this plan.

(4) The amounts shown in this column are attributable to the increase in the actuarial values of each of the named executive officer's combined benefits under AEP's qualified and non-qualified defined benefit plans determined using interest rate and mortality assumptions consistent with those used in the Company's financial statements. See Note 8 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2015 for a discussion of the relevant assumptions. None of the named executive officer received preferential or above-market earnings on deferred compensation. The actual change in pension value in 2015 for Mr. Tierney was ($21,664) and for Mr. Powers was ($701,968).

(5) Amounts shown in the All Other Compensation column for 2015 include: (a) Company contributions to the Company's Retirement Savings Plan, (b) Company contributions to the Company's Supplemental Retirement Savings Plan and (c) perquisites. The amounts are listed in the following table:

All Other Compensation

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Kentucky Power Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) / /	2015/Q4

FOOTNOTE DATA

Type	Nicholas K. Akins	Brian X. Tierney	Robert P. Powers	David M. Feinberg	Charles E. Zebula
Retirement Savings Plan Match	11,687	11,925	11,925	11,925	11,925
Supplemental Retirement Savings Plan Match	78,075	67,100	65,390	44,931	31,008
Perquisites	13,896	5,100	12,919	11,307	11,346
Total	103,658	84,125	90,234	68,163	54,279

Perquisites provided in 2015 included: financial counseling and tax preparation services, and, for Mr. Akins, director's accidental death insurance premium. Executive officers may also have the occasional personal use of event tickets when such tickets are not being used for business purposes, however, there is no associated incremental cost. From time to time executive officers may receive customary gifts from third parties that sponsor sporting events (subject to our policies on conflicts of interest).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Nicholas K. Akins, Chairman of the Board	Columbus, Ohio
2	and Chief Executive Officer	
3		
4	Lisa M. Barton, Vice President	Columbus, Ohio
5		
6	Robert P. Powers, Vice President	Columbus, Ohio
7		
8	Brian X. Tierney, Chief Financial Officer	Columbus, Ohio
9	and Vice President	
10		
11	Dennis E. Welch, Vice President	Columbus, Ohio
12		
13	Mark C. McCullough, Vice President	Columbus, Ohio
14		
15	Lana L. Hillebrand, Vice President	Columbus, Ohio
16		
17	David M. Feinberg, Secretary	Columbus, Ohio
18		
19	Note: The Respondent does not have an Executive Committee	
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46		
47		
48		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

INFORMATION ON FORMULA RATES

FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?

[X] Yes

[ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	Rate Schedule 51	ER06-340
2	Rate Schedule 52	ER06-358
3		
4	PJM Interconnection LLC, Attachment H-14	ER08-1329
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	[X] Yes [ ] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20150604-5184	06/04/2015	ER08-1329	AEP PJM OATT Formula Update	PJM OATT Attach H-14
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
1	204-207	Electric Plant in Service	g	49
2	214	Electric Plant Held for Use	d	46
3	216	Construction Work in Progress	b	1
4	310-311	Sales for Resale	k	1
5	320	Electric Operation and Maintenance Expenses	b	5
6	321	Electric Operation and Maintenance Expenses	b	93
7	323	Electric Operation and Maintenance Expenses	b	185
8	336	Depreciation and Amortization of Electric Plant	b	7
9	354	Distribution of Salaries and Wages	b	28
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

1.

Date Acquired Or Extended	Community (full name)	Period of Franchise & Termination (month/day/year)	Consideration ($ amount or "None")
Renewed January 30, 2015	City of Vicco, Perry County, KY	Twenty (20) year franchise renewal expiring January 29, 2035	20% of Total Street Lighting Amount
Renewed September 1, 2015	City of Flatwoods, Greenup Country, Kentucky	Twenty (20) year franchise expiring August 31, 2035	1% first year, 2% second year, and 3% for the third year and beyond
Renewed October 26, 2015	West Liberty, Morgan County, Kentucky	Twenty (20) year franchise expiring October 25, 2035	25% of the total amount of street lighting, excluding tax and applied FAC revenues

2. None

3. None

4. None

5. None

6. Kentucky Power Local Bank Facility (Case No. 2014-00210)
2nd $25M draw on multiple draw term loan due November 5, 2018
Kentucky Power Local Bank Facility (Case No. 2014-00210)
3rd $25M draw on multiple draw term loan due November 5, 2018

7. None

8. KPCO employees represented by IBEW 978 were provided with a 3.5% general wage increase effective February 17, 2015.
Mitchell Plant employees represented by UWUA 492 were provided with a 2.5% general wage increase for 2015 and 2016 plus a 3% general wage increase for 2017 effective June 1, 2015. (Ratified September 3, 2015)

9. Please refer to the Notes to Financial Statements Pages 122 - 123

10. None

11. (Reserved)

12. Not Used

13. Charles R. Patton elected as Vice President effective 4/23/2015
    Michael S. Isenberg resigned as Vice President effective 4/23/2015
    Dennis E. Welch resigned as Director 08/31/2015
    Dennis E. Welch resigned as Vice President 08/31/2015
    A. Wade Smith elected as Vice President 08/28/2015
    Jeffrey D. Cross resigned as Assistant Secretary 10/30/2015
    William E. Johnson elected as Vice President 08/28/2015

14. Proprietary capital ratio exceeds 30%

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* / /	Year/Period of Report End of 2015/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	2,497,548,422	2,960,216,889
3	Construction Work in Progress (107)	200-201	59,350,976	39,194,443
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		2,556,899,398	2,999,411,332
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	805,037,535	1,040,410,287
6	Net Utility Plant (Enter Total of line 4 less 5)		1,751,861,863	1,959,001,045
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		1,751,861,863	1,959,001,045
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		995,120	995,120
19	(Less) Accum. Prov. for Depr. and Amort. (122)		228,295	221,625
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	0
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		2,038,474	4,753,418
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		0	0
29	Special Funds (Non Major Only) (129)		6,938,909	12,809,589
30	Long-Term Portion of Derivative Assets (175)		12,095	1,005,330
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		9,756,303	19,341,832
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		866,903	795,139
36	Special Deposits (132-134)		1,531,811	2,079,216
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		11,149,887	18,206,323
41	Other Accounts Receivable (143)		110,019	130,610
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		242,308	86,489
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		19,609,035	29,516,559
45	Fuel Stock (151)	227	21,255,090	43,795,830
46	Fuel Stock Expenses Undistributed (152)	227	829,982	1,459,832
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	16,676,493	22,123,437
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	10,028,244	12,375,950

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* / /	Year/Period of Report End of 2015/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		2,092,348	1,845,943
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		2,596,749	2,918,733
61	Accrued Utility Revenues (173)		52,589	2,047,131
62	Miscellaneous Current and Accrued Assets (174)		834,832	0
63	Derivative Instrument Assets (175)		3,054,578	7,363,308
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		12,095	1,005,330
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		90,434,157	143,566,192
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		3,270,739	3,269,949
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	518,260,211	230,078,676
73	Prelim. Survey and Investigation Charges (Electric) (183)		127,491	154,295
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	18,362,928	17,737,023
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		569,259	602,883
82	Accumulated Deferred Income Taxes (190)	234	62,994,524	80,297,444
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		603,585,152	332,140,270
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		2,455,637,475	2,454,049,339

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2015/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	50,450,000	50,450,000
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	527,309,077	517,459,453
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	86,960,274	103,069,147
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-1,645,475	-7,335,603
16	Total Proprietary Capital (lines 2 through 15)		663,073,876	663,642,997
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	0	0
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	870,000,000	820,000,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		277,875	444,600
24	Total Long-Term Debt (lines 18 through 23)		869,722,125	819,555,400
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		2,008,253	3,098,654
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		49,225	102,409
29	Accumulated Provision for Pensions and Benefits (228.3)		10,934,121	10,428,410
30	Accumulated Miscellaneous Operating Provisions (228.4)		466,000	699,000
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		10,664	422,913
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		72,012,344	65,699,264
35	Total Other Noncurrent Liabilities (lines 26 through 34)		85,480,607	80,450,650
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		36,881,901	42,314,868
39	Notes Payable to Associated Companies (233)		18,692,147	45,127,965
40	Accounts Payable to Associated Companies (234)		25,138,556	29,258,819
41	Customer Deposits (235)		26,915,926	26,343,353
42	Taxes Accrued (236)	262-263	-20,945,253	7,929,451
43	Interest Accrued (237)		8,012,650	7,907,923
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2015/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		2,247,993	2,487,654
48	Miscellaneous Current and Accrued Liabilities (242)		26,717,242	63,895,299
49	Obligations Under Capital Leases-Current (243)		895,590	1,189,978
50	Derivative Instrument Liabilities (244)		1,012,757	3,679,112
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		10,664	422,913
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		125,558,845	229,711,509
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		162,493	121,844
57	Accumulated Deferred Investment Tax Credits (255)	266-267	4,050	29,706
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	8,010,573	5,295,155
60	Other Regulatory Liabilities (254)	278	4,085,397	8,348,945
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	60,936,706	85,033,734
63	Accum. Deferred Income Taxes-Other Property (282)		379,980,278	407,120,032
64	Accum. Deferred Income Taxes-Other (283)		258,622,525	154,739,367
65	Total Deferred Credits (lines 56 through 64)		711,802,022	660,688,783
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		2,455,637,475	2,454,049,339

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	670,177,198	814,729,047		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	400,706,295	527,062,307		
5	Maintenance Expenses (402)	320-323	76,957,090	71,812,313		
6	Depreciation Expense (403)	336-337	82,090,907	90,656,236		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	344,928	487,270		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	4,204,635	3,587,770		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	38,616	38,616		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		790,783	289,087		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	22,310,932	21,247,442		
15	Income Taxes - Federal (409.1)	262-263	-61,788,788	10,213,925		
16	- Other (409.1)	262-263	-1,004,589	5,361,083		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	299,048,988	93,266,764		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	236,209,723	85,107,349		
19	Investment Tax Credit Adj. - Net (411.4)	266	-25,656	-96,041		
20	(Less) Gains from Disp. of Utility Plant (411.6)		4,571	4,020		
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		322,012	8,916		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		831,666	978,500		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		587,969,501	739,784,987		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		82,207,697	74,944,060		

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
670,177,198	814,729,047					2
						3
400,706,295	527,062,307					4
76,957,090	71,812,313					5
82,090,907	90,656,236					6
344,928	487,270					7
4,204,635	3,587,770					8
38,616	38,616					9
						10
						11
790,783	289,087					12
						13
22,310,932	21,247,442					14
-61,788,788	10,213,925					15
-1,004,589	5,361,083					16
299,048,988	93,266,764					17
236,209,723	85,107,349					18
-25,656	-96,041					19
4,571	4,020					20
						21
322,012	8,916					22
						23
831,666	978,500					24
587,969,501	739,784,987					25
82,207,697	74,944,060					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		82,207,697	74,944,060		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)					
35	Nonoperating Rental Income (418)		25,255	25,565		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		99,834	178,137		
38	Allowance for Other Funds Used During Construction (419.1)		1,157,911	4,009,386		
39	Miscellaneous Nonoperating Income (421)		2,791,554	546,624		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		4,074,554	4,759,712		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		152,820			
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		452,534	568,279		
46	Life Insurance (426.2)					
47	Penalties (426.3)		12,440	62,551		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		318,441	268,486		
49	Other Deductions (426.5)		946,815	3,212,680		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		1,883,050	4,111,996		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	41,904	58,798		
53	Income Taxes-Federal (409.2)	262-263	-903,645	-2,021,933		
54	Income Taxes-Other (409.2)	262-263	21,798	-176,468		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	25,612,267	1,444,217		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	12,813,116	446,905		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		11,959,208	-1,142,291		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-9,767,704	1,790,007		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		43,405,169	37,828,514		
63	Amort. of Debt Disc. and Expense (428)		716,313	517,866		
64	Amortization of Loss on Reaquired Debt (428.1)		33,624	33,635		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		79,827	859,464		
68	Other Interest Expense (431)		1,113,315	1,164,781		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		799,382	2,048,416		
70	Net Interest Charges (Total of lines 62 thru 69)		44,548,866	38,355,844		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		27,891,127	38,378,223		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		27,891,127	38,378,223		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		103,069,147	179,690,924
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		27,891,127	38,378,223
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31	Common Stock		-44,000,000	(115,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-44,000,000	(115,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		86,960,274	103,069,147
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		86,960,274	103,069,147
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	27,891,127	38,378,223
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	86,679,086	94,769,892
5	Amortization of Regulatory Debits and Credits (Net)	790,783	289,087
6			
7	Mark-to-Market of Risk Management Contracts	1,642,375	203,016
8	Deferred Income Taxes (Net)	75,638,416	9,156,727
9	Investment Tax Credit Adjustment (Net)	-25,656	-96,041
10	Net (Increase) Decrease in Receivables	17,462,354	-23,884,548
11	Net (Increase) Decrease in Inventory	24,132,548	48,108,527
12	Net (Increase) Decrease in Allowances Inventory	2,347,706	8,390,072
13	Net Increase (Decrease) in Payables and Accrued Expenses	-33,743,114	-5,229,388
14	Net (Increase) Decrease in Other Regulatory Assets	-17,001,528	-5,110,010
15	Net Increase (Decrease) in Other Regulatory Liabilities	-4,120,547	2,154,838
16	(Less) Allowance for Other Funds Used During Construction	1,157,911	4,009,386
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):	-47,515,177	48,016,365
19	Customer Deposits	572,573	1,132,067
20	Over/Under Recovered Fuel (Net)	15,403	-1,080,219
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	133,608,438	211,189,222
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-115,352,377	-105,907,357
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-1,157,911	-4,009,386
31	Other (provide details in footnote):		
32			
33	Acquired Assets	-72,486	-1,403,202
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-114,266,952	-103,301,173
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	1,336,932	307,430
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		7
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Contributions in Aid of Construction Proceeds	304,163	518,945
54	(Increase) Decrease in Other Special Deposits	-9,163	
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-112,635,020	-102,474,791
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	50,000,000	290,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Long Term Issuances Costs	-544,268	-1,655,993
66	Net Increase in Short-Term Debt (c)		
67	Proceeds on Capital Leaseback	78,432	1,430,411
68	Notes Payable to Associated Companies		36,563,508
69	Capital Contribution Returned to Parent		-100,000,000
70	Cash Provided by Outside Sources (Total 61 thru 69)	49,534,164	226,337,926
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		-220,000,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Notes Payable to Associated Companies	-26,435,818	
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-44,000,000	-115,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-20,901,654	-108,662,074
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	71,764	52,357
87			
88	Cash and Cash Equivalents at Beginning of Period	795,139	742,782
89			
90	Cash and Cash Equivalents at End of period	866,903	795,139

Schedule Page: 120 Line No.: 18 Column: b

		2015 Cash Flow Incr / (Decr)		2014 Cash Flow Incr / (Decr)
Utility Plant, Net	$	(13,526,497)	$	158,670
Property and Investments, Net		2,721,614		30,685
Special Funds		-		(344,459)
Margin Deposits		556,568		(1,033,258)
Prepayments		(1,619,129)		(3,616,525)
Accrued Utility Revenues, Net		1,994,542		(1,190,355)
Unamortized Debt Expense		543,478		64,147
Other Deferred Debits, Net		(568,587)		1,874,335
Other Comprehensive Income, Net		60,422		281,878
Unamortized Discount/Premium on Long-Term Debt		166,725		166,725
Accumulated Provisions - Misc		(163,850)		733,822
Current and Accrued Liabilities, Net		(38,452,795)		47,827,504
Other Deferred Credits, Net		772,332		3,063,196
Total	**$**	**(47,515,177)**	**$**	**48,016,365**

Schedule Page: 120 Line No.: 37 Column: b

		2015 Cash Flow Incr / (Decr)		2014 Cash Flow Incr / (Decr)
Transformer Sales, Affiliated	$	235,089	$	191,207
Meter Sales, Affiliated		197,039		116,223
Sale of BFP Rotor		904,804		-
Total	**$**	**1,336,932**	**$**	**307,430**

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

INDEX OF NOTES TO FINANCIAL STATEMENTS

GLOSSARY OF TERMS FOR NOTES

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 subsidiaries and affiliates.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KPCo and OPCo.
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.
AFUDC	Allowance for Funds Used During Construction.
AGR	AEP Generation Resources Inc., a nonregulated AEP subsidiary.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ARO	Asset Retirement Obligation.
ASU	Accounting Standards Update.
CWIP	Construction Work in Progress.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
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.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
Interconnection Agreement	An agreement by and among APCo, I&M, KPCo and OPCo which defined the sharing of costs and benefits associated with their respective generation plants. This agreement was terminated January 1, 2014.
IRS	Internal Revenue Service.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
MISO	Midwest Independent Transmission System Operator.

GLOSSARY OF TERMS FOR NOTES (Continued)

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

Term	Meaning
MLR	Member load ratio, the method used to allocate transactions among members of the Interconnection Agreement.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
NO_X	Nitrogen oxide.
OATT	Open Access Transmission Tariff.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third party sales. AEPSC acts as the agent.
OTC	Over the counter.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PCA	Power Coordination Agreement among APCo, I&M, KPCo and WPCo.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
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.
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.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

As a public utility, KPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 170,000 retail customers in its service territory in eastern Kentucky. KPCo also sells power at wholesale to municipalities.

Effective January 1, 2014, the Interconnection Agreement and the AEP System Interim Allowance Agreement were terminated. Also effective January 1, 2014, the FERC approved a PCA among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources. Effective May 2015, the PCA was revised and approved by the FERC to include WPCo. Under the PCA, APCo, I&M, KPCo and WPCo are individually responsible for planning their respective capacity obligations. Further, the Restated and Amended PCA allows, but does not obligate, APCo, I&M, KPCo and WPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.

Also effective January 1, 2014, the FERC approved the creation of a Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as the agent. The Bridge Agreement is an interim arrangement to: (a) address the treatment of purchases and sales made by AEPSC on behalf of member companies that extend beyond termination of the Interconnection Agreement and (b) address how member companies would fulfill their existing obligations under the PJM Reliability Assurance Agreement through the 2014/2015 PJM planning year. Under the Bridge Agreement, AGR is committed to meet capacity obligations of member companies.

AEPSC conducts power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M, KPCo and WPCo. Effective January 1, 2014, and revised in May 2015, power and natural gas risk management activities are allocated based on the member companies' respective equity positions. Risk management activities primarily include the power and natural gas physical transactions, financially-settled swaps and exchange-traded futures. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts. KPCo shared in the revenues and expenses associated with these risk management activities with the member companies.

Under a unit power agreement with AEGCo, an affiliated company, KPCo purchases 390 MWs of Rockport Plant capacity which is 30% of AEGCo's 50% share of the 2,600 MW Rockport Plant. The unit power agreement expires in December 2022. KPCo pays a demand charge for the right to receive the power, which is payable even if the power is not taken.

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of APCo, I&M, KPCo and WPCo and trading and marketing activities originating in SPP generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among APCo, I&M, KPCo, PSO, SWEPCo and WPCo based upon the common shareholder's equity of these companies.

To minimize the credit requirements and operating constraints when operating within PJM, participating AEP companies, including KPCo, agreed to a netting of certain payment obligations incurred by the participating AEP companies against certain balances due to such AEP companies and to hold PJM harmless from actions that any one or more AEP companies may take with respect to PJM.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

KPCo's rates are regulated by the FERC and the KPSC. The FERC also regulates KPCo's affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over the issuances and acquisitions of securities of the public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. For non-power goods and services, the FERC requires a nonregulated affiliate to bill an affiliated public utility company at no more than market while a public utility must bill the higher of cost or market to a nonregulated affiliate. The KPSC also regulates certain intercompany transactions under its affiliate statutes. Both the FERC and state regulatory commissions are permitted to review and audit the relevant books and records of companies within a public utility holding company system.

The FERC regulates wholesale power markets, wholesale power transactions and wholesale transmission operations and rates. KPCo's wholesale power transactions are generally market-based. Wholesale power transactions are cost-based regulated when KPCo negotiates and files a cost-based contract with the FERC or the FERC determines that KPCo has "market power" in the region where the transaction occurs. KPCo has entered into wholesale power supply contracts with various municipalities that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are trued up to actual costs annually.

The KPSC regulates all of the distribution operations and rates and retail transmission rates on a cost basis. The KPSC also regulates the retail generation/power supply operations and rates.

In addition, the FERC regulates the SIA and the Transmission Agreement, all of which are still active and allocate shared system costs and revenues among the utility subsidiaries that are parties to each agreement.

Basis of Accounting

KPCo's accounting is subject to the requirements of the KPSC and the FERC. The financial statements have been prepared in accordance with the Uniform System of Accounts prescribed by the FERC. The principal differences from accounting principles generally accepted in the United States of America (GAAP) include:

- The classification of deferred fuel as noncurrent rather than current.
- The requirement to report deferred tax assets and liabilities separately rather than as a single amount.
- The classification of accrued taxes as a single amount rather than as assets and liabilities.
- The exclusion of current maturities of long-term debt from current liabilities.
- The classification of accrued non-ARO asset removal costs as accumulated depreciation rather than regulatory liabilities.
- The classification of accrued non-ARO asset removal costs as accumulated depreciation rather than regulatory assets.
- The classification of capital lease payments as operating activities instead of financing activities.
- The classification of change in emission allowances held for speculation as investing activities instead of operating activities.
- The classification of gains/losses from disposition of allowances as utility operating expenses rather than as operating revenues.
- The classification of PJM hourly activity for physical transactions as purchases and sales instead of net sales.
- The classification of noncurrent tax liabilities related to the accounting guidance for "Uncertainty in Income Taxes" as a current liability rather than a noncurrent liability.
- The classification of regulatory assets and liabilities related to the accounting guidance for "Accounting for Income Taxes" as separate assets and liabilities rather than as a single amount.
- The presentation of capital leased assets and their associated accumulated amortization as a single amount instead of as separate amounts.
- The classification of factored accounts receivable expense as a nonoperating expense instead of as an operating expense.
- The classification of certain nonoperating revenues as miscellaneous nonoperating income instead of as operating revenue.
- The classification of certain nonoperating expenses as miscellaneous nonoperating expense instead of as operating expense.
- The separate classification of income tax expense for operating and nonoperating activities instead of as a single income tax expense.
- The classification of unamortized loss on reacquired debt in deferred debits rather than in regulatory assets.
- The classification of accumulated deferred investment tax credits in deferred credits rather than in regulatory liabilities and deferred investment tax credits.
- The classification of plant probable of abandonment in Utility Plant and Construction Work in Progress rather than as Other Property, Plant and Equipment.
- The classification of certain other assets and liabilities as current instead of noncurrent.
- The classification of certain other assets and liabilities as noncurrent instead of current.
- The classification of debt issuance costs as noncurrent assets instead of noncurrent liabilities.

Accounting for the Effects of Cost-Based Regulation

As a rate-regulated electric public utility company, KPCo's financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with accounting guidance for "Regulated Operations," KPCo records regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

Use of Estimates

The preparation of these financial statements requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include but are not limited to inventory valuation, allowance for doubtful accounts, long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, storm costs, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Cash and Cash Equivalents

Cash and Cash Equivalents on the statements of cash flows include Cash, Working Fund and Temporary Cash Investments on the balance sheets with original maturities of three months or less.

Supplementary Information

	2015	2014
For the Years Ended December 31,	**(in thousands)**	
Cash Was Paid for:		
Interest (Net of Capitalized Amounts)	$ 43,426	$ 36,062
Income Taxes (Net of Refunds)	(27,317)	18,545
Noncash Acquisitions Under Capital Leases	244	1,471
As of December 31,		
Construction Expenditures Included in Current and Accrued Liabilities	14,112	17,626
Noncash Capital Contribution from Parent	9,849	—

Special Deposits

Special deposits include funds held by trustees primarily for margin deposits for risk management activities.

Inventory

Fossil fuel, materials and supplies inventories are carried at average cost.

Accounts Receivable

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to risk management activities and customer receivables primarily related to other revenue-generating activities.

Revenue is recognized from electric power sales when power is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, KPCo accrues and recognizes, as Accrued Utility Revenues on the balance sheets, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, for KPCo. See "Sale of Receivables - AEP Credit" section of Note 13 for additional information.

Allowance for Uncollectible Accounts

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

Concentrations of Credit Risk and Significant Customers

KPCo does not have any significant customers that comprise 10% or more of its operating revenues as of December 31, 2015.

Management monitors credit levels and the financial condition of KPCo's customers on a continuing basis to minimize credit risk. The KPSC allows recovery in rates for a reasonable level of bad debt costs. Management believes adequate provision for credit loss has been made in the accompanying financial statements.

Emission Allowances

KPCo records emission allowances at cost, including the annual SO_2 and NO_X emission allowance entitlements received at no cost from the Federal EPA. Allowances are consumed in the production of energy and are recorded in Operation Expenses at average cost on the statements of income. The purchases and sales of allowances are reported in the Operating Activities section of the statements of cash flows.

Property, Plant and Equipment

Electric utility property, plant and equipment are stated at original cost. Additions, major replacements and betterments are added to the plant accounts. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in original cost retirements, less salvage, being charged to accumulated depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. The depreciation rates that are established take into account the past history of interim capital replacements and the amount of removal cost incurred and salvage received. These rates and the related lives are subject to periodic review. Removal costs are charged to accumulated depreciation. The costs of labor, materials and overhead incurred to operate and maintain plant and equipment are included in operating expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the criteria under the accounting guidance for "Impairment or Disposal of Long-lived Assets." When it becomes probable that an asset in service or an asset under construction will be abandoned and regulatory cost recovery has been disallowed, the cost of that asset shall be removed from plant-in-service or CWIP and charged to expense.

The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Allowance for Funds Used During Construction

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant.

Valuation of Nonderivative Financial Instruments

The book values of Cash, Special Deposits, Working Fund, accounts receivable, Notes Payable to Associated Companies and accounts payable approximate fair value because of the short-term maturity of these instruments.

Fair Value Measurements of Assets and Liabilities

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability. 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 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.

AEP utilizes its trustee's external pricing service to estimate the fair value of the underlying investments held in the benefit plan trusts. AEP's investment managers review and validate the prices utilized by the trustee to determine fair value. AEP's management performs its own valuation testing to verify the fair values of the securities. AEP receives audit reports of the trustee's operating controls and valuation processes. The trustee uses multiple pricing vendors for the assets held in the trusts.

Assets in the benefits trusts are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equity securities. They are valued based on observable inputs primarily unadjusted quoted prices in active markets for identical assets. Items classified as Level 2 are primarily investments in individual fixed income securities and cash equivalent funds. Fixed income securities generally do not trade on exchanges and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments. Benefit plan assets included in Level 3 are primarily real estate and private equity investments that are valued using methods requiring judgment including appraisals. The fair value of real estate investments is measured using market capitalization rates, recent sales of comparable investments and independent third-party appraisals. The fair value of private equity investments is measured using cost and purchase multiples, operating results, discounted future cash flows and market based comparable data. Depending on the specific situation, one or multiple approaches are used to determine the valuation of a real estate or private equity investment.

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to expense when the fuel is burned or the allowance or consumable is utilized. Fuel cost over-recoveries (the excess of fuel-related revenues over applicable fuel costs incurred) are generally deferred as regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel-related revenues) are generally deferred as regulatory assets. These deferrals are amortized when refunded or when billed to customers in later months with the KPSC's review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the KPSC. On a routine basis, the KPSC reviews and/or audits KPCo's fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. FAC deferrals are adjusted when costs are no longer probable of recovery or when refunds of fuel reserves are probable. Changes in fuel costs, including purchased power, are reflected in rates in a timely manner through the FAC. A portion of margins from off-system sales are given to customers through the FAC.

Revenue Recognition

Regulatory Accounting

KPCo's financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

When regulatory assets are probable of recovery through regulated rates, KPCo records them as assets on its balance sheets. KPCo tests for probability of recovery at each balance sheet date or whenever new events occur. Examples of new events include the issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, KPCo writes off that regulatory asset as a charge against income.

Electricity Supply and Delivery Activities

KPCo recognizes revenues from retail and wholesale electricity sales and electricity transmission and distribution delivery services. KPCo recognizes the revenues on the statements of income upon delivery of the energy to the customer and includes unbilled as well as billed amounts. Wholesale transmission revenue is based on FERC approved formula rate filings made for each calendar year using estimated costs. The annual rate filing is compared to actual costs with an over- or under-recovery being trued-up with interest and refunded or recovered in a future year's rates.

Most of the power produced at KPCo's generation plants is sold to PJM. KPCo purchases power from PJM to supply power to its customers. Generally, these power sales and purchases are reported on a net basis in revenues on the statements of income. However, purchases of power in excess of sales to PJM, on an hourly net basis, used to serve retail load are recorded gross as Operation Expenses on the statements of income.

Physical energy purchases arising from non-derivative contracts are accounted for on a gross basis in Operation Expenses on the statements of income. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's facts and circumstances. Purchases under non-trading derivatives used to serve accrual based obligations are recorded in Operation Expenses on the statements of income. All other non-trading derivative purchases are recorded net in revenues.

In general, KPCo records expenses when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting. KPCo defers the unrealized MTM amounts as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

KPCo engages in power marketing as a major power producer and participant in electricity markets. KPCo also engages in power, capacity, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity risk management activities focused on markets where the AEP System owns assets and adjacent markets. These activities include the purchase-and-sale of energy under forward contracts at fixed and variable prices. These contracts include physical transactions, exchange-traded futures, and to a lesser extent, OTC swaps and options. Certain energy marketing and risk management transactions are with RTOs.

KPCo recognizes revenues and expenses from marketing and risk management transactions that are not derivatives upon delivery of the commodity. KPCo uses MTM accounting for marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or elected normal under the normal purchase normal sale election. The realized gains and losses on marketing and risk management transactions are included in revenues or expense based on the transaction's facts and circumstances. The unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Certain qualifying marketing and risk management derivative transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). KPCo initially records the effective portion of the cash flow hedge's gain or loss as a component of AOCI. When the forecasted transaction is realized and affects net income, KPCo subsequently reclassifies the gain or loss on the hedge from AOCI into revenues or expenses within the same financial statement line item as the forecasted transaction on the statements of income. KPCo defers the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains). See "Accounting for Cash Flow Hedging Strategies" section of Note 9.

Maintenance

Maintenance costs are expensed as incurred. If it becomes probable that KPCo will recover specifically-incurred costs through future rates, a regulatory asset is established to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues.

Income Taxes and Investment Tax Credits

KPCo uses the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence.

When the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

Investment tax credits are accounted for under the flow-through method except where regulatory commissions have reflected investment tax credits in the rate-making process on a deferral basis. Investment tax credits that have been deferred are amortized over the life of the plant investment.

KPCo accounts for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." KPCo classifies interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classifies penalties as Penalties.

Excise Taxes

As an agent for some state and local governments, KPCo collects from customers certain excise taxes levied by those state or local governments on customers. KPCo does not recognize these taxes as revenue or expense.

Debt

Gains and losses from the reacquisition of debt used to finance regulated electric utility plants are deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt is refinanced, the reacquisition costs are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates.

Debt discount or premium and debt issuance expenses are deferred and amortized generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations.

Investments Held in Trust for Future Liabilities

AEP has several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits. All of the trust funds' investments are diversified and managed in compliance with all laws and regulations. The investment strategy for the trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the investment risk of the assets relative to the associated liabilities. To minimize investment risk, the trust funds are broadly diversified among classes of assets, investment strategies and investment managers. Management regularly reviews the actual asset allocations and periodically rebalances the investments to targeted allocations when appropriate. Investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. The investments are reported at fair value under the "Fair Value Measurements and Disclosures" accounting guidance.

Benefit Plans

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies and target asset allocations by plan.

The investment philosophies for AEP's benefit plans support the allocation of assets to minimize risks and optimize net returns. Strategies used include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.
- Managing fees, transaction costs and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style-neutral to limit volatility compared to applicable benchmarks.
- Using alternative asset classes such as real estate and private equity to maximize return and provide additional portfolio diversification.

The objective of the investment policy for the pension fund is to maintain the funded status of the plan while providing for growth in the plan assets to offset the growth in the plan liabilities. The current target asset allocations are as follows:

Pension Plan Assets	Target
Equity	25%
Fixed Income	59%
Other Investments	15%
Cash and Cash Equivalents	1%

OPEB Plans Assets	Target
Equity	65%
Fixed Income	33%
Cash and Cash Equivalents	2%

The investment policy for each benefit plan contains various investment limitations. The investment policies establish concentration limits for securities and prohibit the purchase of securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, the investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law.

For equity investments, the concentration limits are as follows:

- No security in excess of 5% of all equities.
- Cash equivalents must be less than 10% of an investment manager's equity portfolio.
- No individual stock may be more than 10% and 7% for pension and OPEB investments, respectively, of each manager's equity portfolio.
- No investment in excess of 5% of an outstanding class of any company.
- No securities may be bought or sold on margin or other use of leverage.

For fixed income investments, the concentration limits must not exceed:

- 3% in any single issuer.
- 5% for private placements.
- 5% for convertible securities.
- 60% for bonds rated AA+ or lower.
- 50% for bonds rated A+ or lower.
- 10% for bonds rated BBB- or lower.

For obligations of non-government issuers within the fixed income portfolio, the following limitations apply:

- AAA rated debt: a single issuer should account for no more than 5% of the portfolio.
- AA+, AA, AA- rated debt: a single issuer should account for no more than 3% of the portfolio.
- Debt rated A+ or lower: a single issuer should account for no more than 2% of the portfolio.
- No more than 10% of the portfolio may be invested in high yield and emerging market debt combined at any time.

Each investment manager's portfolio is compared to a diversified benchmark index.

A portion of the pension assets is invested in real estate funds to provide diversification, add return and hedge against inflation. Real estate properties are illiquid, difficult to value and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type and risk classification. Real estate holdings include core, value-added and development risk classifications and some investments in Real Estate Investment Trusts, which are publicly traded real estate securities.

A portion of the pension assets is invested in private equity. Private equity investments add return and provide diversification and typically require a long-term time horizon to evaluate investment performance. Private equity is classified as an alternative investment because it is illiquid, difficult to value and not actively traded. The pension plan uses limited partnerships and commingled funds to invest across the private equity investment spectrum. The private equity holdings are with multiple general partners who help monitor the investments and provide investment selection expertise. The holdings are currently comprised of venture capital, buyout and hybrid debt and equity investment instruments. Commingled private equity funds are used to enhance the holdings' diversity.

AEP participates in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. AEP lends securities to borrowers approved by BNY Mellon in exchange for collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the collateral is invested. The difference between the rebate owed to the borrower and the collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is providing modest incremental income with a limited increase in risk.

Trust owned life insurance (TOLI) underwritten by The Prudential Insurance Company is held in the OPEB plan trusts. The strategy for holding life insurance contracts in the taxable Voluntary Employees' Beneficiary Association trust is to minimize taxes paid on the asset growth in the trust. Earnings on plan assets are tax-deferred within the TOLI contract and can be tax-free if held until claims are paid. Life insurance proceeds remain in the trust and are used to fund future retiree medical benefit liabilities. With consideration to other investments held in the trust, the cash value of the TOLI contracts is invested in two diversified funds. A portion is invested in a commingled fund with underlying investments in stocks that are actively traded on major international equity exchanges. The other portion of the TOLI cash value is invested in a diversified, commingled fixed income fund with underlying investments in government bonds, corporate bonds and asset-backed securities.

Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments including commercial paper, certificates of deposit, treasury bills and other types of investment grade short-term debt securities. The cash funds are valued each business day and provide daily liquidity.

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from nonowner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2015 through February 23, 2016, the date that KPCo's 2015 annual report was available to be issued, and has updated such evaluation for disclosure purposes through April 8, 2016. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

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 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 2015-05 "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 adopted ASU 2015-05 prospectively, effective January 1, 2016, with no impact on results of operations, financial position or cash flows.

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 its 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 should 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 should 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 expects the new standard to impact its financial position, but not its results of operations or cash flows. Management plans to adopt ASU 2016-02 effective January 1, 2019.

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI for the years ended December 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 Year Ended December 31, 2015

	Cash Flow Hedges		Pension and OPEB		
	Commodity	Interest Rate and Foreign Currency	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in thousands)		
Balance in AOCI as of December 31, 2014	$ —	$ (161)	$ 3,145	$ (10,320)	$ (7,336)
Change in Fair Value Recognized in AOCI	—	—	—	(522)	(522)
Amounts Reclassified from AOCI	—	60	67	—	127
Net Current Period Other Comprehensive Income (Loss)	—	60	67	(522)	(395)
Pension and OPEB Adjustment Related to Mitchell Plant	—	—	—	6,086	6,086
Balance in AOCI as of December 31, 2015	$ —	$ (101)	$ 3,212	$ (4,756)	$ (1,645)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2014

	Cash Flow Hedges		Pension and OPEB		
	Commodity	Interest Rate and Foreign Currency	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in thousands)		
Balance in AOCI as of December 31, 2013	$ 23	$ (222)	$ 2,677	$ (7,898)	$ (5,420)
Change in Fair Value Recognized in AOCI	347	—	—	(1,114)	(767)
Amounts Reclassified from AOCI	(370)	61	468	—	159
Net Current Period Other Comprehensive Income (Loss)	(23)	61	468	(1,114)	(608)
Pension and OPEB Adjustment Related to Kammer Plant	—	—	—	(1,308)	(1,308)
Balance in AOCI as of December 31, 2014	$ —	$ (161)	$ 3,145	$ (10,320)	$ (7,336)

Reclassifications from Accumulated Other Comprehensive Income

The following table provides details of reclassifications from AOCI for the years ended December 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 7 for additional details.

Reclassifications from Accumulated Other Comprehensive Income (Loss)

	Amount of (Gain) Loss Reclassified from AOCI	
	Years Ended December 31,	
	2015	2014
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Operating Expenses	$ —	$ (516)
Maintenance Expenses	—	(5)
Utility Plant		(6)
Regulatory Assets/(Liabilities), Net (a)	—	(43)
Subtotal – Commodity	—	(570)
Interest Rate and Foreign Currency:		
Interest on Long-term Debt	93	93
Subtotal – Interest Rate and Foreign Currency	93	93
Reclassifications from AOCI, before Income Tax (Expense) Credit	93	(477)
Income Tax (Expense) Credit	33	(168)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	60	(309)
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(41)	(214)
Amortization of Actuarial (Gains)/Losses	141	935
Reclassifications from AOCI, before Income Tax (Expense) Credit	100	721
Income Tax (Expense) Credit	33	253
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	67	468
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ 127	$ 159

(a) Represents realized gains and losses subject to regulatory accounting treatment.

4. RATE MATTERS

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

Plant Transfer

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 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.

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 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 Kentucky Court of Appeals of the April 2015 order. In December 2015, KPCo, the Attorney General and the KPSC filed a joint motion to dismiss the appeals filed with the Kentucky Court of Appeals and in February 2016, the joint motion to dismiss was granted.

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 stipulation agreement between KPCo and certain intervenors was filed with the KPSC that 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 reflected 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. The proposed net increase of $45 million also 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. EFFECTS OF REGULATION

Regulatory assets and liabilities are comprised of the following items:

Regulatory Assets:	December 31, 2015	December 31, 2014	Remaining Recovery Period
	(in thousands)		
Regulatory assets pending final regulatory approval:			
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	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs	192,536	—	25 years
Plant Retirement Costs – Asset Retirement Obligation Costs	7,640	—	25 years
Plant Retirement Costs – Materials and Supplies	4,485	—	25 years
Other Regulatory Assets Approved for Recovery	1,207	556	various
Regulatory Assets Currently Not Earning a Return			
Income Tax Assets	160,942	160,005	21 years
Plant Retirement Costs – Asset Retirement Obligation Costs	58,031	—	25 years
Pension and OPEB Funded Status	52,687	36,460	12 years
Storm Related Costs	10,931	2,349	5 years
Kentucky Deferred Environmental Costs	6,365	—	1 year
Big Sandy Plant, Unit 1 Operating Rider	4,903	—	1 year
Postemployment Benefits	4,557	4,527	5 years
Peak Demand Reduction/Energy Efficiency	4,332	357	2 years
Medicare Subsidy	1,950	2,166	9 years
IGCC Pre-Construction Costs	1,305	—	25 years
Unrealized Loss on Forward Commitments	164	1,835	2 years
Other Regulatory Assets Approved for Recovery	1,848	1,391	various
Total Regulatory Assets Approved for Recovery	513,883	209,646	
Total FERC Account 182.3 Regulatory Assets	$ 518,260	$ 230,079	

Regulatory Liabilities:	December 31, 2015	December 31, 2014	Remaining Refund Period
	(in thousands)		
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Not Paying a Return			
Over-recovered Fuel Costs	$ 1,786	$ 1,770	1 year
Unrealized Gain on Forward Commitments	1,550	5,563	2 years
Income Tax Liabilities	696	855	21 years
Other Regulatory Liabilities Approved for Payment	53	161	various
Total Regulatory Liabilities Approved for Payment	4,085	8,349	
Total FERC Account 254 Regulatory Liabilities	$ 4,085	$ 8,349	

6. 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.

COMMITMENTS

Construction and Commitments

KPCo has substantial construction commitments to support its operations and environmental investments. In managing the overall construction program and in the normal course of business, KPCo contractually commits to third-party construction vendors for certain material purchases and other construction services. KPCo also purchases fuel, materials, supplies, services and property, plant and equipment under contract as part of its normal course of business. Certain supply contracts contain penalty provisions for early termination.

In accordance with the accounting guidance for "Commitments", the following table summarizes KPCo's actual contractual commitments as of December 31, 2015:

Contractual Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in thousands)		
Fuel Purchase Contracts (a)	$ 224,791	$ 276,186	$ 247,937	$ 166,388	$ 915,302
Energy and Capacity Purchase Contracts	35,016	75,370	76,993	77,050	264,429
Construction Contracts for Capital Assets (b)	440	—	—	—	440
Total	$ 260,247	$ 351,556	$ 324,930	$ 243,438	$ 1,180,171

(a) Represents contractual commitments to purchase coal and other consumables as fuel for electric generation along with related transportation of the fuel.

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

GUARANTEES

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

Lease Obligations

KPCo leases certain equipment under master lease agreements. See "Master Lease Agreements" section of Note 12 for disclosure of lease residual value guarantees.

CONTINGENCIES

Insurance and Potential Losses

KPCo maintains insurance coverage normal and customary for an electric utility, subject to various deductibles. KPCo also maintains property and casualty insurance that may cover certain physical damage or third-party injuries caused by cyber security incidents. Insurance coverage includes all risks of physical loss or damage to assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. The insurance programs also generally provide coverage against loss arising from certain claims made by third parties and are in excess of KPCo's retentions. Coverage is generally provided by a combination of the protected cell of EIS and/or various industry mutual and/or commercial insurance carriers.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to a cyber security incident. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could reduce future net income and cash flows and impact financial condition.

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

By-products from the generation of electricity include materials such as ash, slag and sludge. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, the generation plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and nonhazardous materials. KPCo currently incurs costs to dispose of these substances safely.

Superfund addresses clean-up of hazardous substances that are released to the environment. The Federal EPA administers the clean-up programs. Several states enacted similar laws. As of December 31, 2015, there is one site for which KPCo has received an information request which could lead to a Potentially Responsible Party designation. In the instance where KPCo has been named a defendant, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

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

7. BENEFIT PLANS

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Fair Value Measurements of Assets and Liabilities" and "Investments Held in Trust for Future Liabilities" sections of Note 1.

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.

KPCo recognizes its funded status associated with defined benefit pension and OPEB plans in its balance sheets. Disclosures about the plans are required by the "Compensation - Retirement Benefits" accounting guidance. KPCo recognizes an asset for a plan's overfunded status or a liability for a plan's underfunded status and recognizes, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. KPCo records a regulatory asset instead of other comprehensive income for qualifying benefit costs of regulated operations that for ratemaking purposes are deferred for future recovery. The cumulative funded status adjustment is equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction or regulatory asset and deferred gains result in an AOCI equity addition or regulatory liability.

Actuarial Assumptions for Benefit Obligations

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

	Pension Plans		Other Postretirement Benefit Plans	
Assumptions	**2015**	**2014**	**2015**	**2014**
Discount Rate	4.30%	4.00%	4.30%	4.00%
Rate of Compensation Increase	4.35% (a)	4.35% (a)	NA	NA

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

NA Not applicable.

A duration-based method is used to determine the discount rate for the plans. A hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2015, the rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 12% per year, with an average increase of 4.35%.

Actuarial Assumptions for Net Periodic Benefit Costs

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

	Pension Plans		Other Postretirement Benefit Plans	
Assumptions	**2015**	**2014**	**2015**	**2014**
Discount Rate	4.00%	4.70%	4.00%	4.70%
Expected Return on Plan Assets	6.00%	6.00%	6.75%	6.75%
Rate of Compensation Increase	4.35% (a)	4.50% (a)	NA	NA

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

NA Not applicable.

The expected return on plan assets was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation and current prospects for economic growth.

The health care trend rate assumptions as of January 1 of each year used for OPEB plans measurement purposes are shown below:

Health Care Trend Rates	2015	2014
Initial	6.25%	6.50%
Ultimate	5.00%	5.00%
Year Ultimate Reached	2020	2020

Assumed health care cost trend rates have a significant effect on the amounts reported for the OPEB health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(in thousands)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 89	$ (74)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	2,090	(1,714)

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. The plans are monitored to control security diversification and ensure compliance with the investment policy. As of December 31, 2015, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets and Funded Status as of December 31, 2015 and 2014

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

	Pension Plans		Other Postretirement Benefit Plans	
	2015	2014	2015	2014
Change in Benefit Obligation	(in thousands)			
Benefit Obligation as of January 1,	$ 189,224	$ 169,432	$ 50,818	$ 50,806
Service Cost	2,680	2,299	343	472
Interest Cost	7,326	8,041	1,952	2,405
Actuarial (Gain) Loss	(10,971)	18,130	972	100
Benefit Payments	(10,183)	(8,678)	(4,352)	(4,582)
Participant Contributions	—	—	1,150	1,413
Medicare Subsidy	—	—	7	204
Benefit Obligation as of December 31,	$ 178,076	$ 189,224	$ 50,890	$ 50,818
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 184,842	$ 169,578	$ 63,628	$ 62,925
Actual Gain (Loss) on Plan Assets	(3,191)	22,019	(2,597)	3,872
Company Contributions	1,900	1,923	—	—
Participant Contributions	—	—	1,150	1,413
Benefit Payments	(10,183)	(8,678)	(4,352)	(4,582)
Fair Value of Plan Assets as of December 31,	$ 173,368	$ 184,842	$ 57,829	$ 63,628
Funded (Underfunded) Status as of December 31,	$ (4,708)	$ (4,382)	$ 6,939	$ 12,810

Amounts Recognized on the Balance Sheets as of December 31, 2015 and 2014

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2015	2014	2015	2014
	(in thousands)			
Special Funds – Prepaid Benefit Costs	$ —	$ —	$ 6,939	$ 12,810
Accumulated Provision for Pensions and Benefits – Long-term Benefit Liability	(4,708)	(4,382)	—	—
Funded (Underfunded) Status	$ (4,708)	$ (4,382)	$ 6,939	$ 12,810

Amounts Included in AOCI and Regulatory Assets as of December 31, 2015 and 2014

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2015	2014	2015	2014
Components	(in thousands)			
Net Actuarial Loss	$ 54,923	$ 56,506	$ 19,699	$ 12,921
Prior Service Cost (Credit)	100	153	(19,658)	(22,082)
Recorded as				
Regulatory Assets	$ 52,058	$ 43,989	$ 629	$ (7,529)
Deferred Income Taxes	1,038	4,434	(205)	(571)
Net of Tax AOCI	1,927	8,236	(383)	(1,061)

Components of the change in amounts included in AOCI and regulatory assets during the years ended December 31, 2015 and 2014 are as follows:

	Pension Plans		Other Postretirement Benefit Plans	
	2015	2014	2015	2014
Components	(in thousands)			
Actuarial Loss During the Year	$ 2,201	$ 9,392	$ 7,400	$ 461
Amortization of Actuarial Loss	(3,784)	(4,466)	(622)	(746)
Amortization of Prior Service Credit (Cost)	(53)	(57)	2,424	2,424
Change for the Year Ended December 31,	$ (1,636)	$ 4,869	$ 9,202	$ 2,139

Pension and Other Postretirement Benefits Plans' Assets

The fair value tables within Pension and Other Postretirement Benefits Plans' Assets present the classification of assets for AEP within the fair value hierarchy. All Level 1, 2, 3 and Other amounts can be allocated to KPCo as of December 31, 2015 and 2014 using the percentages below:

Pension Plan		Other Postretirement Benefit Plans	
2015	2014	2015	2014
3.6%	3.7%	3.7%	3.8%

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2015:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 315.7	$ —	$ —	$ —	$ 315.7	6.6 %
International	402.3	—	—	—	402.3	8.4 %
Options	—	15.6	—	—	15.6	0.3 %
Real Estate Investment Trusts	4.0	—	—	—	4.0	0.1 %
Common Collective Trust – Global	—	369.7	—	—	369.7	7.8 %
Common Collective Trust – International	—	16.1	—	—	16.1	0.3 %
Subtotal – Equities	722.0	401.4	—	—	1,123.4	23.5 %
Fixed Income:						
Common Collective Trust – Debt	—	34.2	—	—	34.2	0.7 %
United States Government and Agency Securities	—	421.9	—	—	421.9	8.9 %
Corporate Debt	—	1,983.2	—	—	1,983.2	41.6 %
Foreign Debt	—	421.4	0.1	—	421.5	8.8 %
State and Local Government	—	12.8	—	—	12.8	0.3 %
Other – Asset Backed	—	23.4	—	—	23.4	0.5 %
Subtotal – Fixed Income	—	2,896.9	0.1	—	2,897.0	60.8 %
Infrastructure	—	—	42.0	—	42.0	0.9 %
Real Estate	—	—	253.7	—	253.7	5.3 %
Alternative Investments	—	—	378.7	—	378.7	8.0 %
Securities Lending	—	263.0	—	—	263.0	5.5 %
Securities Lending Collateral (a)	—	—	—	(264.7)	(264.7)	(5.5)%
Cash and Cash Equivalents	—	48.6	—	—	48.6	1.0 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	25.9	25.9	0.5 %
Total	$ 722.0	$ 3,609.9	$ 674.5	$ (238.8)	$ 4,767.6	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay collateral received as part of the Securities Lending Program.

(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

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

	Foreign Debt	Infrastructure	Real Estate	Alternative Investments	Total Level 3
			(in millions)		
Balance as of January 1, 2015	$ 0.1	$ 12.5	$ 235.8	$ 378.9	$ 627.3
Actual Return on Plan Assets					
Relating to Assets Still Held as of the Reporting Date	—	(3.6)	12.5	(25.9)	(17.0)
Relating to Assets Sold During the Period	—	0.3	23.8	37.6	61.7
Purchases and Sales	—	32.8	(18.4)	(11.9)	2.5
Transfers into Level 3	—	—	—	—	—
Transfers out of Level 3	—	—	—	—	—
Balance as of December 31, 2015	$ 0.1	$ 42.0	$ 253.7	$ 378.7	$ 674.5

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2015:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 465.1	$ —	$ —	$ —	$ 465.1	29.5%
International	484.3	—	—	—	484.3	30.7%
Options	—	15.6	—	—	15.6	1.0%
Common Collective Trust – Global	—	19.0	—	—	19.0	1.2%
Common Collective Trust – International	—	12.6	—	—	12.6	0.8%
Subtotal – Equities	949.4	47.2	—	—	996.6	63.2%
Fixed Income:						
Common Collective Trust Debt	—	100.9	—	—	100.9	6.4%
United States Government and Agency Securities	—	58.4	—	—	58.4	3.7%
Corporate Debt	—	117.7	—	—	117.7	7.4%
Foreign Debt	—	20.7	—	—	20.7	1.3%
State and Local Government	—	4.2	—	—	4.2	0.3%
Other – Asset Backed	—	8.4	—	—	8.4	0.5%
Subtotal – Fixed Income	—	310.3	—	—	310.3	19.6%
Trust Owned Life Insurance:						
International Equities	—	28.3	—	—	28.3	1.8%
United States Bonds	—	184.3	—	—	184.3	11.7%
Subtotal – Trust Owned Life Insurance	—	212.6	—	—	212.6	13.5%
Cash and Cash Equivalents	44.9	7.2	—	—	52.1	3.3%
Other – Pending Transactions and Accrued Income (a)	—	—	—	5.8	5.8	0.4%
Total	$ 994.3	$ 577.3	$ —	$ 5.8	$ 1,577.4	100.0%

(a) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2014:

Asset Class	Level 1	Level 2	Level 3 (in millions)	Other	Total	Year End Allocation
Equities:						
Domestic	$ 588.6	$ —	$ —	$ —	$ 588.6	11.9 %
International	502.2	—	—	—	502.2	10.1 %
Options	—	14.1	—	—	14.1	0.3 %
Real Estate Investment Trusts	54.3	—	—	—	54.3	1.1 %
Common Collective Trust – Global	—	377.0	—	—	377.0	7.6 %
Common Collective Trust – International	—	18.5	—	—	18.5	0.4 %
Subtotal – Equities	1,145.1	409.6	—	—	1,554.7	31.4 %
Fixed Income:						
Common Collective Trust – Debt	—	30.2	—	—	30.2	0.6 %
United States Government and Agency Securities	—	449.8	—	—	449.8	9.0 %
Corporate Debt	—	1,799.5	—	—	1,799.5	36.2 %
Foreign Debt	—	400.5	0.1	—	400.6	8.1 %
State and Local Government	—	14.9	—	—	14.9	0.3 %
Other – Asset Backed	—	29.1	—	—	29.1	0.6 %
Subtotal – Fixed Income	—	2,724.0	0.1	—	2,724.1	54.8 %
Infrastructure	—	—	12.5	—	12.5	0.3 %
Real Estate	—	—	235.8	—	235.8	4.7 %
Alternative Investments	—	—	378.9	—	378.9	7.6 %
Securities Lending	—	219.8	—	—	219.8	4.4 %
Securities Lending Collateral (a)	—	—	—	(221.5)	(221.5)	(4.5)%
Cash and Cash Equivalents	—	53.3	—	—	53.3	1.1 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	9.9	9.9	0.2 %
Total	$ 1,145.1	$ 3,406.7	$ 627.3	$ (211.6)	$ 4,967.5	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay collateral received as part of the Securities Lending Program.

(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

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

	Foreign Debt	Infrastructure	Real Estate	Alternative Investments	Total Level 3
			(in millions)		
Balance as of January 1, 2014	$ 0.1	$ —	$ 238.2	$ 329.6	$ 567.9
Actual Return on Plan Assets					
Relating to Assets Still Held as of the Reporting Date	—	(0.3)	5.5	32.0	37.2
Relating to Assets Sold During the Period	—	0.1	19.0	15.8	34.9
Purchases and Sales	—	12.7	(26.9)	1.5	(12.7)
Transfers into Level 3	—	—	—	—	—
Transfers out of Level 3	—	—	—	—	—
Balance as of December 31, 2014	$ 0.1	$ 12.5	$ 235.8	$ 378.9	$ 627.3

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2014:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 466.1	$ —	$ —	$ —	$ 466.1	27.5%
International	566.6	—	—	—	566.6	33.5%
Options	—	16.4	—	—	16.4	1.0%
Common Collective Trust – Global	—	29.6	—	—	29.6	1.8%
Subtotal – Equities	1,032.7	46.0	—	—	1,078.7	63.8%
Fixed Income:						
Common Collective Trust – Debt	—	103.7	—	—	103.7	6.1%
United States Government and Agency Securities	—	71.1	—	—	71.1	4.2%
Corporate Debt	—	125.5	—	—	125.5	7.4%
Foreign Debt	—	21.3	—	—	21.3	1.3%
State and Local Government	—	5.9	—	—	5.9	0.3%
Other – Asset Backed	—	4.9	—	—	4.9	0.3%
Subtotal – Fixed Income	—	332.4	—	—	332.4	19.6%
Trust Owned Life Insurance:						
International Equities	—	10.3	—	—	10.3	0.6%
United States Bonds	—	212.1	—	—	212.1	12.5%
Subtotal – Trust Owned Life Insurance	—	222.4	—	—	222.4	13.1%
Cash and Cash Equivalents	46.8	9.6	—	—	56.4	3.3%
Other – Pending Transactions and Accrued Income (a)	—	—	—	4.0	4.0	0.2%
Total	$ 1,079.5	$ 610.4	$ —	$ 4.0	$ 1,693.9	100.0%

(a) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

Determination of Pension Expense

The determination of pension expense or income is based on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return.

The accumulated benefit obligation for the pension plans is as follows:

Accumulated Benefit Obligation	2015	2014
	(in thousands)	
Qualified Pension Plan	$ 174,946	$ 185,344
Nonqualified Pension Plan	5	4
Total as of December 31,	$ 174,951	$ 185,348

For the underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets of these plans as of December 31, 2015 and 2014 were as follows:

	Underfunded Pension Plans	
	December 31,	
	2015	2014
	(in thousands)	
Projected Benefit Obligation	$ 178,076	$ 189,224
Accumulated Benefit Obligation	$ 174,951	$ 185,348
Fair Value of Plan Assets	173,368	184,842
Underfunded Accumulated Benefit Obligation	$ (1,583)	$ (506)

Estimated Future Benefit Payments and Contributions

KPCo expects contributions and payments for the pension plans of $2 million during 2016. The estimated contributions to the pension trust are at least the minimum amount required by the Employee Retirement Income Security Act and additional discretionary contributions may also be made to maintain the funded status of the plan.

The table below reflects the total benefits expected to be paid from the plan or from KPCo's assets. The payments include the participants' contributions to the plan for their share of the cost. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for pension benefits and OPEB are as follows:

	Estimated Payments	
	Pension Plans	Other Postretirement Benefit Plans
	(in thousands)	
2016	$ 10,081	$ 4,682
2017	10,350	4,763
2018	10,776	4,851
2019	11,553	4,914
2020	11,500	5,100
Years 2021 to 2025, in Total	64,046	27,000

Components of Net Periodic Benefit Cost

The following table provides the components of net periodic benefit cost (credit) for the years ended December 31, 2015 and 2014:

	Pension Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
	2015	2014	2015	2014
	(in thousands)			
Service Cost	$ 2,680	$ 2,299	$ 343	$ 472
Interest Cost	7,326	8,041	1,952	2,405
Expected Return on Plan Assets	(9,981)	(9,672)	(4,059)	(4,239)
Amortization of Prior Service Cost (Credit)	53	57	(2,424)	(2,424)
Amortization of Net Actuarial Loss	3,784	4,466	622	746
Net Periodic Benefit Cost (Credit)	3,862	5,191	(3,566)	(3,040)
Capitalized Portion	(1,364)	(1,809)	1,259	1,059
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 2,498	$ 3,382	$ (2,307)	$ (1,981)

Estimated amounts expected to be amortized to net periodic benefit costs (credits) and the impact on the balance sheet during 2016 are shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in thousands)	
Net Actuarial Loss	$ 2,925	$ 1,080
Prior Service Cost (Credit)	51	(2,425)
Total Estimated 2016 Amortization	$ 2,976	$ (1,345)
Expected to be Recorded as		
Regulatory Asset	$ 2,874	$ (1,307)
Deferred Income Taxes	36	(13)
Net of Tax AOCI	66	(25)
Total	$ 2,976	$ (1,345)

American Electric Power System Retirement Savings Plan

KPCo participates in an AEP sponsored defined contribution retirement savings plan, the American Electric Power System Retirement Savings Plan, for substantially all employees. This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for matching contributions. The matching contributions to the plan are 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions. The cost for matching contributions totaled $2.3 million in 2015 and $2.5 million in 2014.

8. BUSINESS SEGMENTS

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

9. 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, 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. 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 December 31, 2015 and 2014:

Notional Volume of Derivative Instruments

Primary Risk Exposure	Volume December 31, 2015	Volume December 31, 2014	Unit of Measure
	(in thousands)		
Commodity:			
Power	7,864	6,689	MWhs
Coal	—	233	Tons
Natural Gas	64	87	MMBtus
Heating Oil and Gasoline	341	261	Gallons
Interest Rate	$ 500	$ 1,047	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's vehicle fleet is exposed to gasoline and diesel fuel price volatility. KPCo utilizes 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. KPCo does not hedge all fuel 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 December 31, 2015 and 2014 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 $656 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 of KPCo's derivative activity on the balance sheets as of December 31, 2015 and 2014:

Fair Value of Derivative Instruments
December 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)			
Derivative Instrument Assets	$ 5,077	$ -	$ -	$ 5,077	$ (2,022)	$ 3,055
Long-Term Portion of Derivative Instrument Assets	59	-	-	59	(47)	12
Derivative Instrument Liabilities	3,690	-	-	3,690	(2,677)	1,013
Long-Term Portion of Derivative Instrument Liabilities	69	-	-	69	(58)	11

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)			
Derivative Instrument Assets	$ 9,691	$ -	$ -	$ 9,691	$ (2,328)	$ 7,363
Long-Term Portion of Derivative Instrument Assets	1,060	-	-	1,060	(55)	1,005
Derivative Instrument Liabilities	5,964	-	-	5,964	(2,285)	3,679
Long-Term Portion of Derivative Instrument Liabilities	477	-	-	477	(54)	423

(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 for the years ended December 31, 2015 and 2014:

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	Years Ended December 31, 2015	2014
	(in thousands)	
Operating Revenues	$ 3,467	$ 13,303
Operation Expenses	3,848	(9)
Maintenance Expenses	(151)	—
Regulatory Assets (a)	1,671	(2,778)
Regulatory Liabilities (a)	(2,922)	2,304
Total Gain on Risk Management Contracts	$ 5,913	$ 12,820

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment.

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, 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 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 on the 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 Operating Revenues or Operation Expenses 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 2015, KPCo did not apply cash flow hedging to outstanding power derivatives. During 2014, KPCo applied cash flow hedging to outstanding power derivatives.

KPCo reclassifies gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income on its balance sheets into Operation Expenses, Maintenance Expenses or Depreciation Expense, as it relates to capital projects, on the statements of income. The impact of 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 on its balance sheets into Interest on Long-term Debt on its statements of income in those periods in which hedged interest payments occur. During 2015 and 2014, KPCo did not apply cash flow hedging to outstanding interest rate derivatives.

During 2015 and 2014, 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 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 on KPCo's balance sheets as of December 31, 2015 and 2014 were:

Impact of Cash Flow Hedges on the Balance Sheets
December 31, 2015

	Commodity	Interest Rate (in thousands)	Total
Hedging Assets (a)	$ —	$ —	$ —
Hedging Liabilities (a)	—	—	—
AOCI Loss Net of Tax	—	(101)	(101)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	—	(60)	(60)

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

	Commodity	Interest Rate (in thousands)	Total
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 Derivative Instrument Assets – Hedges and Derivative Instrument Liabilities – Hedges on KPCo's balance sheets.

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income to Net Income can differ from the estimate above due to market price changes. As of December 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

Management limits credit risk in KPCo's 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.

When management 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 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. The following table represents KPCo's exposure if credit ratings were to decline below a specified rating threshold as of December 31, 2015 and 2014:

	December 31, 2015	December 31, 2014
	(in thousands)	
Amount of Collateral KPCo Would Have Been Required to Post Attributable to RTOs and ISOs	$ 1,003	$ 1,303
Amount of Collateral Attributable to Other Contracts	23	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 December 31, 2015 and 2014:

	December 31, 2015	December 31, 2014
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 750	$ 1,859
Additional Settlement Liability if Cross Default Provision is Triggered	750	1,852

10. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities 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 December 31, 2015 and 2014 are summarized in the following table:

	December 31, 2015		December 31, 2014	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 869,722	$ 963,639	$ 819,555	$ 948,967

Fair Value Measurements of Financial Assets and Liabilities

For a discussion of fair value accounting and the classification of assets and liabilities within the fair value hierarchy, see the "Fair Value Measurements of Assets and Liabilities" section of Note 1.

The following tables set forth, by level within the fair value hierarchy, KPCo's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2015 and 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
December 31, 2015

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

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)		
Derivative Instrument Assets					
Risk Management Commodity Contracts (a) (b)	$ 42	$ 5,328	$ 4,320	$ (2,327)	$ 7,363
Liabilities:					
Derivative Instrument 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 years ended December 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:

Year Ended December 31, 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)	766
Purchases, Issuances and Settlements (d)	(4,313)
Transfers out of Level 3 (f) (g)	240
Changes in Fair Value Allocated to Regulated Jurisdictions (h)	1,626
Balance as of December 31, 2015	$ 2,246

Year Ended December 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) (b) (c)	5,490
Purchases, Issuances and Settlements (d)	(6,084)
Transfers into Level 3 (e) (f)	(750)
Transfers out of Level 3 (f) (g)	(7)
Changes in Fair Value Allocated to Regulated Jurisdictions (h)	3,107
Balance as of December 31, 2014	$ 3,927

(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) 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 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 as of December 31, 2015 and 2014:

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					

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 December 31, 2015 and 2014:

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)

11. INCOME TAXES

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

	Years Ended December 31, 2015	2014
	(in thousands)	
Charged (Credited) to Operating Expenses, Net:		
Current	$ (62,792)	$ 15,575
Deferred	62,839	8,159
Deferred Investment Tax Credits	(26)	(96)
Total	21	23,638
Charged (Credited) to Nonoperating Income, Net:		
Current	(882)	(2,198)
Deferred	12,799	997
Total	11,917	(1,201)
Income Tax Expense	$ 11,938	$ 22,437

The following is a reconciliation of the difference between the amount of federal income taxes computed by multiplying book income before income taxes by the federal statutory tax rate and the amount of income taxes reported:

	Years Ended December 31, 2015	2014
	(in thousands)	
Net Income	$ 27,891	$ 38,378
Income Tax Expense	11,938	22,437
Pretax Income	$ 39,829	$ 60,815
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 13,940	$ 21,285
Increase (Decrease) in Income Taxes Resulting from the Following Items:		
Depreciation	1,361	2,474
AFUDC	(638)	(1,623)
Removal Costs	(1,832)	(2,816)
Investment Tax Credits, Net	(26)	(96)
State and Local Income Taxes, Net	(4,601)	2,973
Tax Adjustments	3,407	372
Other	327	(132)
Income Tax Expense	$ 11,938	$ 22,437
Effective Income Tax Rate	30.0%	36.9%

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

	December 31, 2015		December 31, 2014	
	(in thousands)			
Deferred Tax Assets	$	62,995	$	80,297
Deferred Tax Liabilities		(699,540)		(646,893)
Net Deferred Tax Liabilities	$	(636,545)	$	(566,596)
Property Related Temporary Differences	$	(410,174)	$	(465,514)
Amounts Due from Customers for Future Federal Income Taxes		(27,631)		(29,974)
Deferred State Income Taxes		(90,541)		(84,002)
Deferred Income Taxes on Other Comprehensive Loss		886		3,950
Regulatory Assets		(115,803)		(15,446)
All Other, Net		6,718		24,390
Net Deferred Tax Liabilities	$	(636,545)	$	(566,596)

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.

Net Income Tax Operating Loss Carryforward

KPCo has Kentucky state net income tax operating loss carryforwards of $81 million. As a result, KPCo recognized deferred state income tax benefits in 2015 of $5 million. Management anticipates future taxable income will be sufficient to realize the state net income tax operating loss tax benefits before the state carryforward expires for Kentucky in 2035.

Tax Credit Carryforward

As of December 31, 2015 and 2014, KPCo had unused federal income tax credits of $203 thousand and $275 thousand, respectively, not all of which have an expiration date. Included in the credit carryforward are federal general business tax credits of $189 thousand and $261 thousand as of December 31, 2015 and 2014, respectively. If these credits are not utilized, the federal general business tax credits will expire in the years 2031 through 2034. Management anticipates future federal taxable income will be sufficient to realize the tax benefits of the federal tax credits before they expire unused.

Uncertain Tax Positions

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

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

	Years Ended December 31, 2015	2014
	(in thousands)	
Interest Expense	$ —	$ 20
Reversal of Prior Period Interest Expense	—	71

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

	2015	2014
	(in thousands)	
Balance as of January 1,	$ —	$ 608
Increase – Tax Positions Taken During a Prior Period	—	—
Decrease – Tax Positions Taken During a Prior Period	—	—
Increase – Tax Positions Taken During the Current Year	—	—
Decrease – Tax Positions Taken During the Current Year	—	—
Increase – Settlements with Taxing Authorities	—	2
Decrease – Settlements with Taxing Authorities	—	—
Decrease – Lapse of the Applicable Statute of Limitations	—	(610)
Balance as of December 31,	$ —	$ —

The total amount of unrecognized tax benefits (costs) that, if recognized, would affect the effective tax rate is $0 for 2015 and 2014. Management believes there will be no significant net increase or decrease in unrecognized tax benefits within 12 months of the reporting date.

Federal Tax Legislation

The Tax Increase Prevention Act of 2014 (the 2014 Act) was enacted in December 2014. Included in the 2014 Act was a one-year extension of the 50% bonus depreciation. The 2014 Act also retroactively extended the life of research and development, employment and several energy tax credits, which expired at the end of 2013. The enacted provisions did not materially impact KPCo's net income or financial condition but did have a favorable impact on cash flows in 2015.

The Protecting Americans from Tax Hikes Act of 2015 (PATH) included an extension of the 50% bonus depreciation for three years through 2017, phasing down to 40% in 2018 and 30% in 2019. PATH also provided for the extension of research and development, employment and several energy tax credits for 2015. PATH also includes provisions to extend the wind energy production tax credit through 2016 with a three-year phase-out (2017-2019), and to extend the 30% temporary solar investment tax credit for three years through 2019 and with a two-year phase-out (2020-2021). PATH also provided for a permanent extension of the Research and Development tax credit. The enacted provisions did not materially impact KPCo's net income or financial condition but will have a favorable impact on future cash flows.

State Tax Legislation

During the third quarter of 2013, it was determined that the state of West Virginia had achieved certain minimum levels of shortfall reserve funds. As a result, the West Virginia corporate income tax rate was reduced from 7% to 6.5% in 2014. The enacted provision did not materially impact KPCo's net income, cash flows or financial condition.

12. LEASES

Leases of property, plant and equipment are for remaining periods up to 10 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to Operation Expenses and Maintenance Expenses in accordance with rate-making treatment for regulated operations. For capital leases, a capital lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. The components of rental costs are as follows:

Lease Rental Costs	Years Ended December 31, 2015	2014
	(in thousands)	
Net Lease Expense on Operating Leases	$ 1,603	$ 1,466
Amortization of Capital Leases	1,148	1,112
Interest on Capital Leases	171	189
Total Lease Rental Costs	$ 2,922	$ 2,767

The following table shows the property, plant and equipment under capital leases and related obligations recorded on KPCo's balance sheets.

	December 31, 2015	2014
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Production	$ 2,338	$ 2,517
Other Property, Plant and Equipment	2,920	4,120
Total Property, Plant and Equipment Under Capital Leases	5,258	6,637
Accumulated Amortization	2,354	2,348
Net Property, Plant and Equipment Under Capital Leases	$ 2,904	$ 4,289
Obligations Under Capital Leases		
Noncurrent	$ 2,008	$ 3,099
Current	896	1,190
Total Obligations Under Capital Leases	$ 2,904	$ 4,289

Future minimum lease payments consisted of the following as of December 31, 2015:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2016	$ 997	$ 1,928
2017	880	1,819
2018	560	1,596
2019	267	1,423
2020	190	1,238
Later Years	275	3,297
Total Future Minimum Lease Payments	3,169	$ 11,301
Less Estimated Interest Element	265	
Estimated Present Value of Future Minimum Lease Payments	$ 2,904	

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 December 31, 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.

13. FINANCING ACTIVITIES

Long-term Debt

The following details long-term debt outstanding as of December 31, 2015 and 2014:

Type of Debt	Maturity	Weighted Average Interest rate as of December 31, 2015	Interest Rate Ranges as of December 31, 2015	Interest Rate Ranges as of December 31, 2014	Outstanding as of December 31, 2015	Outstanding as of December 31, 2014
					(in thousands)	
Senior Unsecured Notes	2017-2039	5.81%	4.18%-8.13%	4.18%-8.13%	$ 730,000	$ 730,000
Pollution Control Bonds (a)	2015-2016 (b)	0.02%	0.02%	0.05%	65,000	65,000
Other Long-term Debt	2018	1.93%	1.83%-2.11%	1.74%	75,000	25,000
Unamortized Discount, Net					(278)	(445)
Total Long-term Debt					$ 869,722	$ 819,555

(a) For KPCo's pollution control bond, the interest rate is subject to periodic adjustment and may be purchased on demand at periodic interest adjustment dates. Insurance policies support certain series.

(b) KPCo's pollution control bond is subject to redemption earlier than the maturity date. Consequently, this bond has been classified for maturity purposes based on the mandatory redemption date.

Long-term debt outstanding as of December 31, 2015 is payable as follows:

	2016	2017	2018	2019	2020	After 2020	Total
				(in thousands)			
Principal Amount	$ 65,000	$ 325,000	$ 75,000	$ —	$ —	$ 405,000	$ 870,000
Unamortized Discount, Net							(278)
Total Long-term Debt							$ 869,722

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%. As of December 31, 2015, none of KPCo's retained earnings have restrictions related to the payment of dividends to Parent.

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 December 31, 2015 and 2014 are included in Notes Payable to Associated Companies on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the years ended December 31, 2015 and 2014 are described in the following table:

Year	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 December 31,	Authorized Short-Term Borrowing Limit
			(in thousands)			
2015	$ 52,477	$ 25,768	$ 19,242	$ 10,409	$ 18,692	$ 225,000
2014	52,414	86,715	24,309	40,255	45,128	250,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool for the years ended December 31, 2015 and 2014 are summarized in the following table:

Years Ended December 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	0.87%	0.37%	0.54%	0.40%	0.48%	0.44%
2014	0.59%	0.24%	0.33%	0.26%	0.31%	0.28%

Interest expense and interest income related to the Utility Money Pool are included in Interest on Debt to Associated Companies and Interest and Dividend Income, respectively, on KPCo's statements of income. For amounts borrowed from and advanced to the Utility Money Pool, KPCo incurred the following amounts of interest expense and earned the following amounts of interest income, respectively, for the years ended December 31, 2015 and 2014:

	Years Ended December 31, 2015	2014
	(in thousands)	
Interest Expense	$ 80	$ 46
Interest Income	10	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. 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 $38 million and $46 million as of December 31, 2015 and 2014, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold were $3 million and $3 million for the years ended December 31, 2015 and 2014.

KPCo's proceeds on the sale of receivables to AEP Credit were $528 million and $604 million for the years ended December 31, 2015 and 2014, respectively.

14. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "AEP System Tax Allocation Agreement" section of Note 11 in addition to "Corporate Borrowing Program – AEP System" and "Sale of Receivables – AEP Credit" sections of Note 13.

Interconnection Agreement

In accordance with management's December 2010 announcement and October 2012 filing with the FERC, the Interconnection Agreement was terminated effective January 1, 2014. The AEP System Interim Allowance Agreement which provided for, among other things, the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement was also terminated.

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

Effective January 1, 2014, the FERC approved the following agreements. See "Organization" section of Note 1.

- A PCA among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources. Effective May 2015, the PCA was revised and approved by the FERC to include WPCo.
- A Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as the agent to address open commitments related to the termination of the Interconnection Agreement and responsibilities to PJM.
- A Power Supply Agreement between AGR and OPCo for AGR to supply capacity and energy needs of OPCo's retail load.

AEPSC conducts power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M, KPCo, PSO, SWEPCo and WPCo. Effective January 1, 2014 and revised in May 2015, power and natural gas risk management activities for APCo, I&M, KPCo and WPCo are allocated based on the four member companies' respective equity positions, while power and natural gas risk management activities for PSO and SWEPCo are allocated based on the Operating Agreement. Risk management activities primarily include power and natural gas physical transactions, financially-settled swaps and exchange-traded futures. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts.

Operating Agreement

PSO, SWEPCo and AEPSC are parties to the Operating Agreement which was approved by the FERC. The Operating Agreement requires PSO and SWEPCo to maintain adequate annual planning reserve margins and requires that capacity in excess of the required margins be made available for sale to other operating companies as capacity commitments. In January 2014, the FERC approved a modification of the Operating Agreement to address changes resulting from an anticipated March 2014 SPP power market change. Subsequently and in March 2014, SPP changed from an energy imbalance service market to a fully integrated power market. In alignment with the new SPP integrated power market and according to the modified Operating Agreement, PSO and SWEPCo operate as standalone entities and offer their respective generation into the SPP power market. SPP then economically dispatches resources. By offering their resources separately, PSO and SWEPCo no longer purchase or sell energy to each other to serve their respective internal load or off-system sales.

System Integration Agreement (SIA)

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity. Margins resulting from trading and marketing activities originating in PJM and MISO generally accrue to the benefit of APCo, I&M, KPCo and WPCo, while trading and marketing activities originating in SPP generally accrue to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among APCo, I&M, KPCo, PSO, SWEPCo and WPCo based upon the equity positions of these companies.

The SIA was designed to function as an umbrella agreement in addition to the Interconnection Agreement (prior to January 1, 2014) and the Operating Agreement, each of which controlled the distribution of revenues and expenses.

Affiliated Revenues and Purchases

The following table shows the revenues derived from sales under the Interconnection Agreement, direct sales to affiliates, net transmission agreement sales and other revenues for the years ended December 31, 2015 and 2014:

Related Party Revenues	Years Ended December 31, 2015	Years Ended December 31, 2014	
	(in thousands)		
Sales under Interconnection Agreement	$ —	$ 5,480	(a)
Auction Sales to OPCo (b)	4,183	—	
Transmission Agreement Sales	7,277	1,726	
Other Revenues	354	308	
Total Affiliated Revenues	$ 11,814	$ 7,514	

(a) Includes December 2013 true-up activity subsequent to agreement termination.
(b) Refer to the Ohio Auctions section below for further information regarding this amount.

The following table shows the purchased power expenses incurred for purchases under the Interconnection Agreement and from affiliates for the years ended December 31, 2015 and 2014:

Related Party Purchases	Years Ended December 31, 2015	2014
	(in thousands)	
Purchases under Interconnection Agreement	$ —	$ 1,242 (a)
Direct Purchases from AEGCo	99,475	115,001
Total Affiliated Purchases	$ 99,475	$ 116,243

(a)Includes December 2013 true-up activity subsequent to agreement termination.

System Transmission Integration Agreement (STIA)

AEP's STIA provided for the integration and coordination of the planning, operation and maintenance of transmission facilities. Since the FERC approved the cancellation of the STIA effective June 1, 2014, the coordinated planning, operation and maintenance of transmission facilities are the responsibility of the RTOs and the STIA is no longer necessary. Similar to the SIA, the STIA functioned as an umbrella agreement in addition to the Transmission Agreement (TA) and the Transmission Coordination Agreement (TCA). The TA and TCA are both still active. The STIA contained two service schedules that governed:

- The allocation of transmission costs and revenues.
- The allocation of third-party transmission costs and revenues and AEP System dispatch costs.

APCo, I&M, KGPCo, KPCo, OPCo and WPCo are parties to the TA, effective November 2010, which defines how transmission costs through PJM OATT are allocated among the AEP East Companies, KGPCo and WPCo on a 12-month average coincident peak basis.

KPCo's net charges recorded as a result of the TA for the years ended December 31, 2015 and 2014 were $13.3 million and $7.5 million, respectively, and were recorded in Operation Expenses on KPCo's statements of income.

PSO, SWEPCo and AEPSC are parties to the TCA, dated January 1, 1997, by and among PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two AEP utility subsidiaries. The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with overseeing the coordinated planning of the transmission facilities of the parties to the agreement.

Ohio Auctions

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. Certain affiliated entities, including KPCo, participated in the auction process and were awarded tranches of OPCo's SSO load. Refer to the Affiliated Revenues and Purchases section above for amounts related to these transactions. See Note 9 - Derivatives and Hedging for further information.

Unit Power Agreements (UPA)

A UPA between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant unless it is sold to another utility. Subsequently, I&M assigns 30% of the power to KPCo. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) net of amounts received by AEGCo from any other sources, sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The I&M Power Agreement will continue in effect until the expiration of the lease term of Unit 2 of the Rockport Plant unless extended in specified circumstances.

Pursuant to an assignment between I&M and KPCo and a UPA between KPCo and AEGCo, AEGCo sells KPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo pays to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KPCo UPA ends in December 2022.

I&M Barging, Urea Transloading and Other Services

I&M provides barging, urea transloading and other transportation services to affiliates. Urea is a chemical used to control NO_X emissions at certain generation plants in the AEP System. KPCo recorded expenses of $5 million and $5 million for the years ended December 31, 2015 and 2014 for urea transloading provided by I&M. These expenses were recorded as Operation Expenses.

Central Machine Shop

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. APCo defers the cost of performing these services on the balance sheet, then transfers the cost to the affiliate for reimbursement. KPCo recorded its assigned portion of these billings as capital or maintenance expenses depending on the nature of the services received. These billings are recoverable from customers. KPCo's billed amounts were $1.3 million and $1.2 million for the years ended December 31, 2015 and 2014, respectively.

Sales and Purchases of Property

KPCo had affiliated sales and purchases of electric property individually amounting to $100 thousand or more, sales and purchases of meters and transformers, and sales and purchases of transmission property. There were no gains or losses recorded on the transactions. The following table shows the sales and purchases, recorded in Utility Plant on the balance sheets at net book value, for the years ended December 31, 2015 and 2014:

	Years Ended December 31, 2015	2014
	(in thousands)	
Sales	$ 1,337	$ 307
Purchases	1,871	349

Intercompany Billings

KPCo performs certain utility services for other AEP subsidiaries when necessary or practical. The costs of these services are billed on a direct-charge basis, whenever possible, or on reasonable basis of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital.

AEPSC

AEPSC provides certain managerial and professional services to AEP's subsidiaries. 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. AEPSC and its billings are subject to regulation by the FERC. KPCo's total billings from AEPSC for the years ended December 31, 2015 and 2014 were $60 million and $53 million, respectively.

15. PROPERTY, PLANT AND EQUIPMENT

Depreciation

KPCo provides for depreciation of Utility Plant on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following table provides total annual composite depreciation rates by functional class:

Year	Steam	Transmission	Distribution	General
		(in percentages)		
2015	0.4	2.2	3.5	10.0
2014	3.5	1.6	3.4	4.2

The composite depreciation rate generally includes a component for non-asset retirement obligation (non-ARO) removal costs, which is credited to accumulated depreciation. Actual removal costs incurred are charged to accumulated depreciation.

Asset Retirement Obligations

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 Utility Plant.

The following is a reconciliation of the 2015 and 2014 aggregate carrying amounts of ARO for KPCo:

Year	ARO as of January 1,	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO as of December 31,
			(in thousands)			
2015	$ 65,699	$ 3,554	$ 4,236	$ (5,564)	$ 4,087 (a)	$ 72,012
2014	20,526	2,309	42,578	(643)	929	65,699

(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.

Jointly-owned Electric Facilities

KPCo has a 50.0% ownership share of Units 1 and 2 at the Mitchell Generating Station. In addition to KPCo, the Mitchell Generating Station is jointly-owned by WPCo. Using its own financing, each participating company is obligated to pay its share of the costs in the same proportion as its ownership interest. KPCo's proportionate share of the operating costs associated with this facility is included in its statements of income and the investment and accumulated depreciation are reflected in its balance sheets under Utility Plant as follows:

	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in thousands)	
KPCo's Share as of December 31, 2015					
Mitchell Generating Station, Units 1 and 2 (a)	Coal	50.0 %	$ 1,013,825	$ 9,346	$ 353,583
KPCo's Share as of December 31, 2014					
Mitchell Generating Station, Units 1 and 2 (a)	Coal	50.0 %	$ 1,007,186	$ 16,132	$ 339,803

(a) Operated by KPCo.

16. COST REDUCTION PROGRAM

2014 Disposition Plant Severance

Management retired several generation plants or units of plants during 2015. The 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.

KPCo's disposition plant severance activity for the year ended December 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 December 31, 2015
		(in thousands)			
$ 4,539	$ (1)	$ 11	$ 2,397 (a)	$ —	$ 2,152

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

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				(5,220,773)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(839,801)
3	Preceding Quarter/Year to Date Changes in Fair Value				(1,113,905)
4	Total (lines 2 and 3)				(1,953,706)
5	Balance of Account 219 at End of Preceding Quarter/Year				(7,174,479)
6	Balance of Account 219 at Beginning of Current Year				(7,174,479)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				5,239,210
8	Current Quarter/Year to Date Changes in Fair Value				390,496
9	Total (lines 7 and 8)				5,629,706
10	Balance of Account 219 at End of Current Quarter/Year				(1,544,773)

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1	(221,545)	22,616	(5,419,702)		
2	60,421	(370,689)	(1,150,069)		
3		348,073	(765,832)		
4	60,421	(22,616)	(1,915,901)	38,378,223	36,462,322
5	(161,124)		(7,335,603)		
6	(161,124)		(7,335,603)		
7	60,422		5,299,632		
8			390,496		
9	60,422		5,690,128	27,891,127	33,581,255
10	(100,702)		(1,645,475)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	2,415,236,066	2,415,236,066
4	Property Under Capital Leases	2,903,842	2,903,842
5	Plant Purchased or Sold		
6	Completed Construction not Classified	71,657,913	71,657,913
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	2,489,797,821	2,489,797,821
9	Leased to Others		
10	Held for Future Use	7,750,601	7,750,601
11	Construction Work in Progress	59,350,976	59,350,976
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	2,556,899,398	2,556,899,398
14	Accum Prov for Depr, Amort, & Depl	805,037,535	805,037,535
15	Net Utility Plant (13 less 14)	1,751,861,863	1,751,861,863
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	798,231,357	798,231,357
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	6,806,178	6,806,178
22	Total In Service (18 thru 21)	805,037,535	805,037,535
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	805,037,535	805,037,535

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
					15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		[redacted]
2	Fabrication		
3	Nuclear Materials		
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)		[redacted]
7	Nuclear Fuel Materials and Assemblies		[redacted]
8	In Stock (120.2)		
9	In Reactor (120.3)		
10	SUBTOTAL (Total 8 & 9)		[redacted]
11	Spent Nuclear Fuel (120.4)		
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)		
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)		[redacted]
15	Estimated net Salvage Value of Nuclear Materials in line 9		[redacted]
16	Estimated net Salvage Value of Nuclear Materials in line 11		[redacted]
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		[redacted]
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		[redacted]

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
[redacted]	[redacted]		1
[redacted]			2
[redacted]			3
[redacted]			4
[redacted]			5
[redacted]	[redacted]		6
[redacted]	[redacted]		7
			8
			9
[redacted]	[redacted]		10
			11
			12
			13
[redacted]	[redacted]		14
[redacted]	[redacted]		15
[redacted]	[redacted]		16
[redacted]	[redacted]		17
			18
			19
			20
			21
[redacted]	[redacted]		22

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	52,919	
4	(303) Miscellaneous Intangible Plant	18,465,102	4,856,209
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	18,518,021	4,856,209
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	2,358,529	
9	(311) Structures and Improvements	94,643,744	2,338,561
10	(312) Boiler Plant Equipment	1,232,867,890	21,912,082
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	165,239,494	2,323,540
13	(315) Accessory Electric Equipment	33,945,568	7,395,703
14	(316) Misc. Power Plant Equipment	16,571,635	568,091
15	(317) Asset Retirement Costs for Steam Production	59,915,567	8,323,354
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,605,542,427	42,861,331
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power PLant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)		
36	D. Other Production Plant		
37	(340) Land and Land Rights		
38	(341) Structures and Improvements		
39	(342) Fuel Holders, Products, and Accessories		
40	(343) Prime Movers		
41	(344) Generators		
42	(345) Accessory Electric Equipment		
43	(346) Misc. Power Plant Equipment		
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)		
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,605,542,427	42,861,331

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	35,137,018	682,400
49	(352) Structures and Improvements	6,708,785	783
50	(353) Station Equipment	189,876,317	5,575,604
51	(354) Towers and Fixtures	94,969,430	64,561
52	(355) Poles and Fixtures	97,069,718	3,341,482
53	(356) Overhead Conductors and Devices	134,922,102	2,327,688
54	(357) Underground Conduit	11,590	
55	(358) Underground Conductors and Devices	106,066	
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	558,801,026	11,992,518
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	7,504,521	
61	(361) Structures and Improvements	4,372,006	11,053
62	(362) Station Equipment	90,957,784	2,546,900
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	187,008,388	7,689,855
65	(365) Overhead Conductors and Devices	192,263,552	17,035,107
66	(366) Underground Conduit	6,836,059	164,318
67	(367) Underground Conductors and Devices	10,272,856	559,640
68	(368) Line Transformers	123,697,804	5,550,168
69	(369) Services	55,866,593	2,378,083
70	(370) Meters	24,713,912	806,529
71	(371) Installations on Customer Premises	19,962,653	1,291,897
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	3,485,765	170,511
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	726,941,893	38,204,061
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	1,524,731	
87	(390) Structures and Improvements	21,591,464	219,264
88	(391) Office Furniture and Equipment	1,683,333	
89	(392) Transportation Equipment	14,768	
90	(393) Stores Equipment	164,548	6,255
91	(394) Tools, Shop and Garage Equipment	3,603,761	372,092
92	(395) Laboratory Equipment	141,764	67,146
93	(396) Power Operated Equipment	5,931	
94	(397) Communication Equipment	8,008,138	1,070,856
95	(398) Miscellaneous Equipment	1,569,294	48,760
96	SUBTOTAL (Enter Total of lines 86 thru 95)	38,307,732	1,784,373
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	81,055	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	38,388,787	1,784,373
100	TOTAL (Accounts 101 and 106)	2,948,192,154	99,698,492
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	2,948,192,154	99,698,492

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
[redacted]	[redacted]	[redacted]	[redacted]		1
					2
			52,919		3
10,926,046			12,395,265		4
10,926,046			12,448,184		5
[redacted]	[redacted]	[redacted]	[redacted]		6
[redacted]	[redacted]	[redacted]	[redacted]		7
134,468		2,633,823	4,857,884		8
35,709,546			61,272,759		9
373,601,731		-7,697	881,170,544		10
					11
52,371,847			115,191,187		12
12,900,885			28,440,386		13
6,373,985			10,765,741		14
60,216,336			8,022,585		15
541,308,798		2,626,126	1,109,721,086		16
[redacted]	[redacted]	[redacted]	[redacted]		17
					18
					19
					20
					21
					22
					23
					24
					25
[redacted]	[redacted]	[redacted]	[redacted]		26
					27
					28
					29
					30
					31
					32
					33
					34
					35
[redacted]	[redacted]	[redacted]	[redacted]		36
					37
					38
					39
					40
					41
					42
					43
					44
					45
541,308,798		2,626,126	1,109,721,086		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
			35,819,418		48
16,411			6,693,157		49
1,567,440		-18,796	193,865,685		50
56,308			94,977,683		51
499,645			99,911,555		52
36,007		18,796	137,232,579		53
			11,590		54
			106,066		55
					56
					57
2,175,811			568,617,733		58
					59
			7,504,521		60
			4,383,059		61
273,492			93,231,192		62
					63
1,336,457			193,361,786		64
2,195,251			207,103,408		65
18,743			6,981,634		66
73,658			10,758,838		67
3,038,106			126,209,866		68
287,441			57,957,235		69
589,062			24,931,379		70
1,279,398			19,975,152		71
					72
50,511			3,605,765		73
					74
9,142,119			756,003,835		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			1,524,731		86
7,192			21,803,536		87
			1,683,333		88
			14,768		89
			170,803		90
			3,975,853		91
			208,910		92
			5,931		93
62,827			9,016,167		94
			1,618,054		95
70,019			40,022,086		96
					97
			81,055		98
70,019			40,103,141		99
563,622,793		2,626,126	2,486,893,979		100
					101
					102
					103
563,622,793		2,626,126	2,486,893,979		104

Schedule Page: 204 Line No.: 49 Column: g

The investment and related accumulated depreciation in Generation Step-Up Units (GSUs) in plant accounts 352-353 included in KPCo's generation formula rates are identified by a query of the plant accounting system.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47	TOTAL				

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Carrs Site (8500)	8/17/82		6,778,355
3				
4	Ramey Substation (4205)	10/1/09	2016	627,604
5				
6	Sub Transmission Lines - Prestonburg Middle Creek			
7	46 kV Line (9069)	11/01/14	2016	344,642
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			7,750,601

Schedule Page: 214 Line No.: 46 Column: d

The generation assets in Electric Plant Held for Future Use included in KPCo's generation formula rates are identified by a query of the plant accounting system.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	BS U1 Gas Conversion	28,404,368
2	Mitchell Controls Upgrade KY	3,641,364
3	KYPCo Distr Pre Eng Parent	1,556,654
4	KP/VoltVar Circ Reconfig DLine	1,054,968
5	ML1 PURCHASE ID FAN HUBS	1,033,536
6	ML2 V CATALYST REPLACEMENT 1 L	1,177,183
7	T/KY/KY Transmisison Work	1,271,108
8	KYPCo Trans Pre Eng Parent	1,242,506
9	WS-CI-KEPCo-G PPB	5,924,690
10	ET-CI-KEPCo-T ASSET IMP	1,249,220
11	Ed-Ci-Kepco-D Ast Imp	1,737,856
12	ET-CI-KyPCo-T Drvn D Asset Imp	1,923,068
13	Other Minor Projects Under $1,000,000	9,134,455
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	59,350,976

Schedule Page: 216 Line No.: 1 Column: b

The generation assets in Construction Work in Progress included in KPCo's generation formula rates are identified by a query of the plant accounting system.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2015/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	1,018,732,500	1,018,732,500		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	82,090,907	82,090,907		
4	(403.1) Depreciation Expense for Asset Retirement Costs	344,928	344,928		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	33,948,618	33,948,618		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	116,384,453	116,384,453		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	523,810,612	523,810,612		
13	Cost of Removal	8,008,018	8,008,018		
14	Salvage (Credit)	3,816,274	3,816,274		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	528,002,356	528,002,356		
16	Other Debit or Cr. Items (Describe, details in footnote):	191,116,760	191,116,760		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	798,231,357	798,231,357		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	394,966,319	394,966,319		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production				
25	Transmission	181,033,260	181,033,260		
26	Distribution	212,283,949	212,283,949		
27	Regional Transmission and Market Operation				
28	General	9,947,829	9,947,829		
29	TOTAL (Enter Total of lines 20 thru 28)	798,231,357	798,231,357		

Schedule Page: 219 Line No.: 8 Column: c

Big Sandy Ash Pond deferred depreciation expense (ref: Case No. 2012-00578)	$31,742,344
Environmental costs recovered per KPSC Order (ref: Case No. 2014-00396)	2,200,642
Asbestos ARO depreciation expense in account 1080013	5,632
Total	$33,948,618

Schedule Page: 219 Line No.: 13 Column: c

Includes ($3,260,655) of removal cost in retirement work in progress (RWIP).

Schedule Page: 219 Line No.: 14 Column: c

Includes ($1,524,568) of salvage in retirement work in progress (RWIP).

Schedule Page: 219 Line No.: 16 Column: c

Adjustment for Big Sandy U2 retirement - additional cost of removal reserve	$188,940,096
Asbestos ARO reserve in account 1080013	2,176,664
Total	$191,116,760

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
				3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
				42

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	43,795,830	21,255,090	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	1,459,832	829,982	Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	5,247,572	5,040,576	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	16,462,260	11,274,805	Electric
8	Transmission Plant (Estimated)	114,678	54,994	Electric
9	Distribution Plant (Estimated)	273,667	262,608	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	25,260	43,510	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	22,123,437	16,676,493	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	67,379,099	38,761,565	

Schedule Page: 227 Line No.: 11 Column: c

Assigned to - Other includes customer account, administrative and general expenses.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2016 No. (d)	2016 Amt. (e)
1	Balance-Beginning of Year	155,209.00	12,375,950	54,080.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	29,882.00		30,171.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9		500.00	38,500		
10					
11					
12					
13					
14					
15	Total	500.00	38,500		
16					
17	Relinquished During Year:				
18	Charges to Account 509	52,612.00	2,386,206		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Consent Decree Surrender			39,988.00	
23					
24					
25					
26					
27					
28	Total			39,988.00	
29	Balance-End of Year	132,979.00	10,028,244	44,263.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	362.00		362.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	362.00			
40	Balance-End of Year			362.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)		87		
44	Net Sales Proceeds (Other)		87		
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2017		2018		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
54,080.00		54,080.00		1,387,905.00		1,705,354.00	12,375,950	1
[redacted]								2
								3
				54,271.00		114,324.00		4
								5
[redacted]								6
								7
								8
						500.00	38,500	9
								10
								11
								12
								13
								14
						500.00	38,500	15
[redacted]								16
								17
						52,612.00	2,386,206	18
[redacted]								19
								20
[redacted]								21
						39,988.00		22
								23
								24
								25
								26
								27
						39,988.00		28
54,080.00		54,080.00		1,442,176.00		1,727,578.00	10,028,244	29
[redacted]								30
								31
								32
								33
								34
								35
[redacted]								
362.00		362.00		24,244.00		25,692.00		36
				723.00		723.00		37
								38
				361.00		723.00		39
362.00		362.00		24,606.00		25,692.00		40
[redacted]								41
								42
					23		110	43
					23		110	44
								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2016 No. (d)	2016 Amt. (e)
1	Balance-Beginning of Year	13,439.00			
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	15,246.00		15,163.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	9,942.00			
19	Other:				
20		13,439.00			
21	Cost of Sales/Transfers:				
22	Associated Electric Coop	500.00			
23	Chief Power Finance, LLC	500.00			
24	Monongahela Power	1,000.00			
25	Fathom Energy LLC	500.00			
26					
27					
28	Total	2,500.00			
29	Balance-End of Year	2,804.00		15,163.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)		392,500		
34	Gains		392,500		
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2017		2018		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
						13,439.00		1
[redacted]								2
								3
						30,409.00		4
								5
[redacted]								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
[redacted]								16
								17
						9,942.00		18
[redacted]								19
						13,439.00		20
[redacted]								21
						500.00		22
						500.00		23
						1,000.00		24
						500.00		25
								26
								27
						2,500.00		28
						17,967.00		29
[redacted]								30
								31
								32
							392,500	33
							392,500	34
								35
[redacted]								
								36
								37
								38
								39
								40
[redacted]								41
								42
								43
								44
								45
								46

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL					

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	PJM #Y2-045	153	186	153	186
3	PJM #Y2-086			430	186
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	NONE				
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Deferred Storm Expense	2,349,222		593	2,349,222	
2	Kentucky PSC Case No. 2009-00352					
3	Amortz period: July 2010 - June 2015					
4						
5	Deferred Storm Expenses	12,146,000	4,377,336	593	1,214,600	15,308,736
6	Kentucky PSC Case No. 2014-00396					
7						
8	SFAS 109 Deferred FIT	86,494,450	19,231,874	190,282-3	26,083,456	79,642,868
9						
10	SFAS 109 Deferred SIT	73,509,355	13,474,397	283	5,684,632	81,299,120
11						
12	Post In-Service AFUDC Hanging Rock/	598,824		406	33,408	565,416
13	Jefferson 765 KV Line					
14	Amortz period: Dec 1984 - Nov 2032					
15						
16	Depreciation Expense - Hanging Rock/	93,313		406	5,208	88,105
17	Jefferson 765 KV Line					
18	Amortz period: Dec 1984 - Nov 2032					
19						
20	Deferred DSM Expense	357,422	7,357,457	456,908	3,382,486	4,332,393
21						
22	Deferred Carbon Management Research	75,018	200,000	188,506	275,018	
23	Kentucky PSC Case 2008-00308 & 2009-00459					
24	Amortz period: July 2010 - June 2018					
25						
26	RTO Deferred Equity Carrying Charge	(62,940)	12,588			-50,352
27						
28	BridgeCo Transmission Org Funding	190,853		407,421	32,471	158,382
29	Amortz period: Jan 2005 - Dec 2019					
30	FERC Docket AC04-101-000					
31						
32	Other PJM Integration	201,636		407,421	34,305	167,331
33	Amortz period: Jan 2005 - Dec 2019					
34	FERC Docket AC04-101-000					
35						
36	Carrying Charges - RTO Startup Costs	126,188		407,421	21,469	104,719
37	Amortz period: Jan 2005 - Dec 2019					
38	FERC Docket AC04-101-000					
39						
40	Alliance RTO Deferred Expense	99,891		407,421	16,995	82,896
41	Amortz period: Jan 2005 - Dec 2019					
42	FERC Docket AC04-101-000					
43						
44	TOTAL	230,078,676	448,499,008	[redacted]	160,317,473	518,260,211

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	SFAS 112 Post Employment Benefit	4,526,999	637,010	Various	607,065	4,556,944
2						
3	SFAS 158 Employers' Accounting for Defined	36,460,394	21,945,673	Various	5,719,180	52,686,887
4	Benefit Pension and Other Postretirement Plans					
5						
6	Unrealized Loss on Forward Commitments	1,835,356	3,507,758	Various	5,179,409	163,705
7						
8	SFAS 106 Medicare Subsidy	2,166,200		926	216,620	1,949,580
9						
10	Asset Retirement Obligations	8,287,118	14,471,448	Various	22,758,566	
11						
12	Asset Transfer Rider Under Recovery	623,377	7,898,601	Various	8,521,978	
13	Kentucky PSC Case No. 2012-00578					
14	Kentucky PSC Case No. 2014-00396					
15						
16	Under Recovery of PJM True-Up		107,473	Various		107,473
17						
18	Cost of Removal-Big Sandy Coal		4,249,319		66,401,618	-62,152,299
19	Kentucky PSC Case No. 2014-00396					
20						
21	NBV - AROs Retired Plants		65,670,606	108	7,640,012	58,030,594
22	Kentucky PSC Case No. 2014-00396					
23						
24	M&S - Retiring Plants		4,627,404	154	142,417	4,484,987
25	Kentucky PSC Case No. 2014-00396					
26						
27	Unrecovered Plant - Big Sandy		255,341,849			255,341,849
28	Kentucky PSC Case No. 2014-00396					
29						
30	IGCC Pre-Construction Costs		1,331,253	506	26,624	1,304,629
31	Kentucky PSC Case No. 2014-00396					
32						
33	CCS FEED Study Costs		872,858	506	17,457	855,401
34	Kentucky PSC Case No. 2014-00396					
35						
36	Spent AROs - Big Sandy Coal		7,640,012			7,640,012
37	Kentucky PSC Case No. 2014-00396					
38						
39	Big Sandy Recovery Over/Under		423,838	407	1,077,379	-653,541
40	Kentucky PSC Case No. 2014-00396					
41						
42	Big Sandy Retirement Rider Unit 2 O&M		744,460	506		744,460
43	Kentucky PSC Case No. 2014-00396					
44	TOTAL	230,078,676	448,499,008		160,317,473	518,260,211

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2015/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS: Written off During the Quarter/Year Account Charged (d)	CREDITS: Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Unrecovered Purchased Power-PPA		232,630	555,254		232,630
2	Kentucky PSC Case No. 2014-00396					
3						
4	Deferred Depreciation - Environmental		2,299,429	403	98,787	2,200,642
5	Kentucky PSC Case No. 2014-00396					
6						
7	Carrying Charge - Environmental		4,831,123	421,431	184,947	4,646,176
8	Kentucky PSC Case No. 2014-00396					
9						
10	CC - Unrec Equity - Environmental		94,542	1823	2,421,069	-2,326,527
11	Kentucky PSC Case No. 2014-00396					
12						
13	Deferred O&M - Environmental		1,676,021	Various	142,547	1,533,474
14	Kentucky PSC Case No. 2014-00396					
15						
16	Deferred Consumable Expense Environmental		294,369	502	26,909	267,460
17	Kentucky PSC Case No. 2014-00396					
18						
19	Deferred Property Tax - Environmental		45,130	408	1,619	43,511
20	Kentucky PSC Case No. 2014-00396					
21						
22	BS1OR Under Recovery		4,902,550	407		4,902,550
23	Kentucky PSC Case No. 2014-00396					
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	230,078,676	448,499,008		160,317,473	518,260,211

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Deferred Property Tax	15,922,168	16,522,064	408	15,313,111	17,131,121
2						
3	Agency Fees - Factored A/R	919,211	10,842,669	Various	10,998,332	763,548
4						
5	Unamortized Credit Line Fees	518,417	475,714	431	690,884	303,247
6	Amortized thru July 2017					
7						
8	Deferred Lease Assets	216,492	95,818	Various	243,206	69,104
9						
10	Miscellaneous Items	879	59,745	Various	60,024	600
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress	159,856				95,308
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	17,737,023				18,362,928

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Provision Revenue Refunds	11,065,012	402,861
3	Accrued BK ARO Exp	22,994,742	25,204,320
4	Int Exp Capd for Tax	7,961,442	8,218,545
5	Pension	-16,693,434	-16,503,324
6	Prelim Survey Big Sandy	11,191,555	493
7	Other	13,116,878	15,817,056
8	TOTAL Electric (Enter Total of lines 2 thru 7)	49,636,195	33,139,951
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	30,661,249	29,854,573
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	80,297,444	62,994,524

Notes

Schedule Page: 234 Line No.: 17 Column: a

Page 234 Line 17	Beginning of Year	End of Year
Non Utility –Acct 190.2	679,720	274,963
SFAS 109	26,031,588	28,693,585
SFAS 133	86,759	54,225
SFAS 87	3,863,182	831,800
	30,661,249	29,854,573

Summary:

1901001	Accum DFIT –Other	28,295,412
1902001	Accum DFIT-Other Income & Deductions	274,963
1901002	Accum DSIT	4,844,539
1903001	Accum DFIT- SFAS 109 Flow Thru	28,450,729
1904001	Accum DFIT – SFAS 109 Excess	242,857
	Subtotal A/C 190	62,108,500
190010/11	ADIT Federal – Pension OCI/NON UMWA	831,800
190015	ADIT Federal Hdg CF Int Rate	54,224
	Subtotal A/C 190	886,024
	Total A/C 190	62,994,524

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common Stock	2,000,000	50.00	
2				
3	Total Common Stock	2,000,000		
4				
5				
6	Preferred Stock: None			
7				
8	Total Preferred Stock			
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
1,009,000	50,450,000					1
						2
1,009,000	50,450,000					3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account 208 - Donations Received From Stockholders	
2	Contributions by Parent Company prior to 2015	514,648,268
3	Capital Contribution from Parent	9,849,624
4		
5	Subtotal - Account 208	524,497,892
6		
7	Account 209 - Reduction in Par or Stated Value of Capital Stock	
8		
9	Account 210 - Gain on Resale/Cancellation of Reacquired Capital Stock	
10		
11	Account 211 - Miscellaneous Paid-In-Capital	2,811,185
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40	TOTAL	527,309,077

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221 - BONDS		
2	SUBTOTAL ACCOUNT 221 - BONDS		
3			
4	ACCOUNT 222 - REQUIRED BONDS		
5	SUBTOTAL ACCOUNT 222 - REQUIRED BONDS		
6			
7	ACCOUNT 223 - ADVANCES FROM ASSOCIATED COMPANIES		
8	SUBTOTAL ACCOUNT 223 - ADVANCES FROM ASSOCIATED COMPANIES		
9			
10	ACCOUNT 224 - OTHER LONG-TERM DEBT		
11	Senior Unsecured Notes - 5.625%, Series D	75,000,000	736,575
12			
13	Senior Unsecured Notes - 6.000%, Series E	325,000,000	2,277,883
14	KPSC Authority Docket No.2006-0034		1,667,250 D
15			
16	Amortization of Cash Flow Hedges on 6.000% SUN		
17			
18	Senior Unsecured Notes - 7.250%, State Commission Authority Case # 2008-00442	40,000,000	217,919
19			
20	Senior Unsecured Notes - 8.030%, State Commission Authority Case # 2008-00442	30,000,000	148,032
21			
22	Senior Unsecured Notes - 8.130%, State Commission Authority Case # 2008-00442	60,000,000	342,285
23			
24	Senior Unsecured Notes - 4.180%, Series A	120,000,000	638,464
25	State Commission Authority Case# 2014-00210		
26			
27	Senior Unsecured Notes - 4.33%, Series B	80,000,000	414,941
28	State Commission Authority Case# 2014-00210		
29			
30	WVEDA Mitchell Project Series 2014A, State Commision Authority Case# 2013-00410	65,000,000	675,501
31			
32	Local Bank Term Loan, State Commission Authority Case# 2014-00210	75,000,000	509,274
33	TOTAL	870,000,000	7,628,124

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1			
2	SUBTOTAL ACCOUNT 224 - OTHER LONG-TERM DEBT	870,000,000	7,628,124
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	870,000,000	7,628,124

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
06/13/2003	12/01/2032	06/13/2003	12/01/2032	75,000,000	4,218,750	11
						12
09/11/2007	09/15/2017	09/11/2007	09/15/2017	325,000,000	19,500,000	13
						14
						15
		09/11/2007	09/15/2017		92,956	16
						17
06/18/2009	06/18/2021	06/18/2009	06/18/2021	40,000,000	2,900,000	18
						19
06/18/2009	06/18/2029	06/18/2009	06/18/2029	30,000,000	2,409,000	20
						21
06/18/2009	06/18/2039	06/18/2009	06/18/2039	60,000,000	4,878,000	22
						23
9/30/2014	9/30/2026	9/30/2014	9/30/2026	120,000,000	5,016,000	24
						25
						26
12/30/2014	12/30/2026	12/30/2014	12/30/2026	80,000,000	3,464,000	27
						28
						29
6/26/2014	4/1/2036	6/26/2014	6/26/2017	65,000,000	28,345	30
						31
11/5/2014	11/5/2018	11/5/2014	11/5/2018	75,000,000	898,118	32
[redacted]				870,000,000	43,405,169	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
				870,000,000	43,405,169	2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				870,000,000	43,405,169	33

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) X An Original (2) _ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 256 Line No.: 24 Column: a

The Senior Unsecured Note was issued on September 30, 2014. The interest rate is 4.180% and the maturity date is September 30, 2026. Issuance expenses totaling $638,464 will be amortized through the maturity date.

Schedule Page: 256 Line No.: 27 Column: a

The Senior Unsecured Note was issued on December 30, 2014. The interest rate is 4.33% and the maturity date is December 30, 2026. Issuance expenses totaling $414,941 will be amortized through the maturity date.

Schedule Page: 256 Line No.: 30 Column: a

The WVEDA Mitchell Project Series 2014A bonds was issued on June 26, 2014 and has a maturity date of April 1, 2036. It bears a weekly floating interest rate. Issuance expenses totaling $675,501 will be amortized through the maturity date.

Schedule Page: 256 Line No.: 32 Column: a

The $75 million multiple draw term loan was issued on November 5, 2014. The interest rate is variable and the maturity date is November 5, 2018.
The initial draw took place on November 5, 2014 for $25 million.
The second draw took place on March 31, 2015 for $25 million.
The Third draw took place on October 15, 2015 for $25 million.
Issuance expenses totally $509,274 will be amortized through the maturity date.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	27,891,127
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	-151,982,995
28	Show Computation of Tax:	
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

Name of Respondent Kentucky Power Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4

FOOTNOTE DATA

Schedule Page: 261 Line No.: 28 Column: b

Net Income for the Year (Per Page 117)	27,891
Federal Income Tax Expense	19,016
State Income Tax Expense	(7,079)
	39,828
Excess Tax vs Book Depreciation	(37,144)
Accrued Book ARO Expense	(2,416)
AFUDC and Other Capitalization Differences	(31)
Book Unit of Property Adjustment	(2,652)
Removal Cost	(12,212)
Pollution Control Equipment	9,444
Property Tax	1,049
Provision for Revenue Refunds	(31,021)
Deferred Fuel	15
Self Insurance / Worker's Comp	(28)
Accrued Book Pension Expense	1,654
Misc Book Accruals, Reserves & Deferrals	(10,761)
Deferred Storm Damage	(814)
Demand Side Management Expense	(3,974)
Book Deferred Revenue	(432)
ATR Under Recovery	-
SFAS 106 - Post Retirement Benefit Expense	(2,793)
Tax Accruals & Deferrals	(3,174)
Mark-to-Market	144
Emission Allowances	1,998
Tax Loss Big Sandy Retirement	(99,785)
	-
	-
	-
	-
Other	60
Taxable Income Before State Tax Deduction	(153,045)
State and Local Income Tax	(1,062)
Federal Taxable Income	(151,983)
	35%
Federal Income Tax at Statutory Rate	(53,194)
Adjustment Due to System Consolidation (a)	-
Tax Provision Adjustment	-
Tax Credit CFWD	(120)
Estimated Tax Currently Payable (b)	(53,314)
Adjustments of Prior Year's Accruals	(9,378)
Estimated Current Federal Income Taxes	(62,692)

(a) Represents the allocation of the estimated current year net operating tax loss of American Electric Power Company, Inc.

(b) The Company joins in the filing of a consolidated Federal income tax return with its affiliated companies in the AEP system. The allocation of the AEP System's consolidated Federal income tax to the System companies allocates the benefit of current tax losses to the System companies giving rise to them in determining their current tax expense. The tax loss of the System parent company, American Electric Power Company, Inc., is allocated to its subsidiaries with taxable income. With the exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the consolidating group.

INSTRUCTION 2.
* The tax computation above represents an estimate of the Company's allocated portion of the System consolidated Federal income tax. The computation of actual 2015 System Federal income taxes will not be available until the consolidated Federal income tax return is completed and filed by September 2016. The actual allocation of the System consolidated Federal income tax to the members of the consolidated group will not be available until after the consolidated federal income tax return is filed

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	FEDERAL TAXES:					
2	INCOME TAX	-10,943,661		-62,692,433	-27,482,974	-198
3	INCOME TAX - IRS Audit					
4	FICA - 2015	817,521		4,103,107	4,236,191	
5	Unemployment - 2015	40,922		26,728	57,442	
6						
7	Federal Excise Tax - 2014			1,978	1,978	
8	Federal Excise Tax - 2015			5,004	5,004	
9						
10	STATE INC. TAX - FIN 48					
11						
12	STATE OF ILLINOIS:					
13	Income NOL 2011			-1,833	-1,833	
14	2012					
15	2013					
16	2014	-75,604		136,965	61,361	
17	2015			-346,247	-316,101	
18						
19	STATE OF KENTUCKY:					
20	Income 2011					
21	2012					
22	2013					
23	2014	-280,550		-145,872	-426,422	
24	2015				426,422	
25						
26	License Fee 2014	-45				
27	License Fee 2015			640	640	
28						
29	Unemployment - KY 2015	9,452		39,473	37,585	
30						
31	PUBLIC SER COMM'S-2014		534,777	534,777		
32	PUBLIC SER COMM'S-2015			566,102	1,132,203	
33						
34	USE TAX - 2014	118,203	55,187	21,743	84,759	
35	USE TAX - 2015			1,086,781	1,011,207	
36						
37						
38	SALES TAX - 2014		382,098		-382,098	
39	SALES TAX - 2015				297,141	
40						
41	TOTAL	7,929,451	972,062	-36,530,811	-7,721,702	-198

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	REAL & PERS PROP-2012	-1,994		3,337	1,343	
2	REAL & PERS PROP-2013	762,384		66,772	829,156	
3	REAL & PERS PROP-2014	11,602,960		751,268	4,068,420	
4	REAL & PERS PROP-2015			12,464,368		
5	PERS PROP LEASED-2014	18,510		131,730	150,239	
6	PERS PROP LEASED-2015			45,900		
7	REAL PROP LEASES-2014	256		-181	74	
8	REAL PROP LEASES-2015			25,500	12,584	
9						
10	STATE OF WEST VIRGINIA:					
11	Income 2009	-63,670				
12	2012					
13	2013					
14	2014	962,311		77,391	1,039,702	
15	2015			-700,327	431,291	
16						
17	Franchise - 2011					
18	2012					
19	2013	9,765		1,546	11,311	
20	2014					
21	2015					
22						
23	State of Utah					
24	Franchise 2015			100	100	
25						
26	USE - 2014	5,031		2,562	7,593	
27	USE - 2015			35,933	29,994	
28						
29	State Bus & Occp Tax-2014	330,320		-10,000	320,320	
30	State Bus & Occp Tax-2015			3,961,843	3,632,393	
31						
32	Real & Pers Prop Taxes	1,341,172			1,341,172	
33	Real & Pers Prop Taxes	3,170,134		-69,843	1,557,762	
34	Real & Pers Prop Taxes			3,258,521		
35	PERS PROP LEASED-2014	2,007		752	2,759	
36	PERS PROP LEASED-2015			2,007		
37						
38	WV License Fee - 2014	45		45	45	
39						
40	WV State Unemployment -	12,781		54,509	54,072	
41	TOTAL	7,929,451	972,062	-36,530,811	-7,721,702	-198

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1						
2	OK State License Fee 2012					
3	Michigan License Fee 2011					
4	Tennessee License Fee 2011					
5	Utah License Fee 2011					
6	Wyoming License Fee 2011					
7						
8	STATE OF OHIO:					
9	State Unemployment 2015					
10						
11	OH CAT TAX - 2014	15,000		-8,967	6,033	
12	OH CAT TAX - 2015			39,985	30,085	
13						
14	STATE OF MICHIGAN:					
15	Income 2011					
16	2012					
17	2013					
18	2014	5,040		10,808	15,848	
19	2015			-13,677	-6,700	
20						
21	OTHER:					
22	REAL/PERS PROP-LA-2014	-197		197		
23	REAL/PERS PROP-LA-2015			197	197	
24	PA Gross Receipts - Audit	71,358				
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	7,929,451	972,062	-36,530,811	-7,721,702	-198

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
-46,153,318		-61,788,788			-903,645	2
						3
684,437		2,196,169			1,906,938	4
10,208		14,898			11,830	5
						6
		1,978				7
		5,004				8
						9
						10
						11
						12
		-1,833				13
						14
						15
		139,062			-2,097	16
-30,147		-348,120			1,873	17
						18
						19
						20
						21
						22
		-139,852			-6,020	23
-426,422		-26,676			26,676	24
						25
						26
		640				27
						28
11,340		31,741			7,732	29
						30
		534,777				31
	566,101	566,102				32
						33
		1,422			20,321	34
119,000	43,426	12,097			1,074,684	35
						36
						37
						38
	297,141					39
						40
-20,945,253	906,668	-40,482,445			3,951,634	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
		3,337				1
		66,772				2
8,285,808		12,159,155			-11,407,887	3
12,464,368		-43,511			12,507,879	4
		131,730				5
45,900		45,900				6
		-181				7
12,916		25,500				8
						9
						10
-63,670						11
						12
						13
		81,209			-3,818	14
-1,131,618		-705,487			5,160	15
						16
						17
						18
		1,546				19
						20
						21
						22
						23
		100				24
						25
					2,562	26
5,939					35,933	27
						28
		-10,000				29
329,450		3,961,843				30
						31
		1,299,669			-1,299,669	32
1,542,529		1,250,063			-1,319,906	33
3,258,521					3,258,521	34
		1,757			-1,005	35
2,007		1,002			1,005	36
						37
		45				38
						39
13,218		20,163			34,346	40
-20,945,253	906,668	-40,482,445			3,951,634	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
		-8,967				11
9,900		39,985				12
						13
						14
						15
						16
						17
		10,860			-52	18
-6,977		-13,753			76	19
						20
						21
		197				22
					197	23
71,358						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
-20,945,253	906,668	-40,482,445			3,951,634	41

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) X An Original (2) _ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 262 Line No.: 2 Column: f

(198)- Fuel Tax Credit

Schedule Page: 262 Line No.: 38 Column: a

Consist of a prepayment for sales tax only; a collect & remit tax. Beginning in 2009, included for purpose of reporting all prepaid tax activity.

Schedule Page: 262 Line No.: 39 Column: a

Consist of a prepayment for sales tax only; a collect & remit tax. Beginning in 2009, included for purpose of reporting all prepaid tax activity.

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility	[redacted]					
2	3%						
3	4%						
4	7%						
5	10%	29,706			411.4	25,656	
6							
7							
8	TOTAL	29,706				25,656	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)	[redacted]					
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
4,050	Various		5
			6
			7
4,050			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
			48

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	TV Pole Attachments	90,446	454	652,495	653,830	91,781
2						
3	Customer Advance Receipts	1,376,129	142,143	27,888,732	30,971,603	4,459,000
4						
5	Deferred Gain:	150,472	124	7,345		143,127
6	Fiber Optic Agrmts-In Kind Svc					
7	Amortize through August 2025					
8						
9	Deferred Revenue	89,618	451	13,556		76,062
10	Fiber Optic Lines-Sold-Defd Rev					
11	Amortize through January 2025					
12						
13	IPP - System Upgrade Credits	277,687			9,135	286,822
14						
15	Miscellaneous	2,726	Various	11,550	9,151	327
16						
17	Federal Mitigation Deferral (NSR)	1,110,644				1,110,644
18						
19	Contract Settlement Reserve	237,602	Various	466,448	537,394	308,548
20						
21	Noble Energy Deferred Lease	1,870,111	421	431,564		1,438,547
22						
23	Contribution Aid of Construction	89,720	107,108	991,447	997,442	95,715
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	5,295,155		30,463,137	33,178,555	8,010,573

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	85,033,734	2,897,763	24,097,028
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	85,033,734	2,897,763	24,097,028
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	85,033,734	2,897,763	24,097,028
18	Classification of TOTAL			
19	Federal Income Tax	85,033,734	2,897,763	24,097,028
20	State Income Tax			
21	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
[redacted]							1
[redacted]							2
							3
		208	2,897,763			60,936,706	4
							5
							6
							7
			2,897,763			60,936,706	8
[redacted]							9
							10
							11
							12
							13
							14
							15
							16
			2,897,763			60,936,706	17
[redacted]							18
			2,897,763			60,936,706	19
							20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account	Balance at Beginning of Year	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1	Amounts Credited to Account 411.1
	(a)	(b)	(c)	(d)
1	Account 282			
2	Electric	351,449,785	86,392,133	102,220,481
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	351,449,785	86,392,133	102,220,481
6	SFAS 109	55,670,247		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	407,120,032	86,392,133	102,220,481
10	Classification of TOTAL			
11	Federal Income Tax	407,120,032	86,392,133	102,220,481
12	State Income Tax			
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
[redacted]							1
		208	6,951,861			328,669,576	2
							3
							4
			6,951,861			328,669,576	5
		Various	10,280,156	Various	5,920,611	51,310,702	6
							7
							8
			17,232,017		5,920,611	379,980,278	9
[redacted]							10
			17,232,017		5,920,611	379,980,278	11
							12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Deferred Fuel Costs	3,593,836	6,500,463	5,830,791
4	Mark to Market	1,988,580	1,400,840	2,659,277
5	Capitalized Software - Book	2,588,613	1,189,651	
6	Emission Allowances	4,296,232	128,460	704,563
7	Reg Asset - SFAS 112	1,584,450	143,383	132,902
8	Other	11,039,463	156,054,424	61,140,944
9	TOTAL Electric (Total of lines 3 thru 8)	25,091,174	165,417,221	70,468,477
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other	129,648,193		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	154,739,367	165,417,221	70,468,477
20	Classification of TOTAL			
21	Federal Income Tax	70,737,179	160,693,356	64,493,297
22	State Income Tax	84,002,188	4,723,865	5,975,180
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
[redacted]							1
[redacted]							2
				Various	1	4,263,509	3
						730,143	4
						3,778,264	5
						3,720,129	6
						1,594,931	7
2,105,122	1,293,244					106,764,821	8
2,105,122	1,293,244				1	120,851,797	9
[redacted]							10
							11
							12
							13
							14
							15
							16
							17
4,406		Various	16,803,463	Various	24,921,592	137,770,728	18
2,109,528	1,293,244		16,803,463		24,921,593	258,622,525	19
[redacted]							20
2,109,528	1,293,244		11,118,831		11,447,196	168,081,887	21
			5,684,632		13,474,397	90,540,638	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 18 Column: a

Line 18 Other - Detail	Balance at Beginning of Year	Balance at End of Year
Non-Utility	137,505	141,911
SFAS 109	129,510,688	137,628,817
SFAS 133	0	0
Total	$129,648,193	$137,770,728

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Home Energy Assistance Program	160,631	various	668,689	561,181	53,123
2						
3	SFAS 109 Deferred FIT	854,459	various	206,975	48,571	696,055
4						
5	Unrealized Gain on Forward Commitments	5,562,690	various	93,548,926	89,535,879	1,549,643
6						
7	Green Pricing Option	746			8	754
8						
9	Over Recovered Fuel Cost	1,770,419	various	4,282,153	4,297,556	1,785,822
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	8,348,945	[redacted]	98,706,743	94,443,195	4,085,397

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	227,938,316	237,174,718
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	141,395,643	148,091,606
5	Large (or Ind.) (See Instr. 4)	165,925,395	169,912,260
6	(444) Public Street and Highway Lighting	1,796,458	1,255,493
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	537,055,812	556,434,077
11	(447) Sales for Resale	96,827,042	220,112,981
12	TOTAL Sales of Electricity	633,882,854	776,547,058
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	633,882,854	776,547,058
15	Other Operating Revenues		
16	(450) Forfeited Discounts	3,414,518	3,813,866
17	(451) Miscellaneous Service Revenues	509,911	390,827
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	5,950,205	5,581,767
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	4,663,172	5,329,652
22	(456.1) Revenues from Transmission of Electricity of Others	21,756,538	23,065,877
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	36,294,344	38,181,989
27	TOTAL Electric Operating Revenues	670,177,198	814,729,047

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
[redacted]				1
2,192,126	2,350,431	137,944	138,958	2
[redacted]				3
1,322,718	1,360,775	30,458	30,387	4
2,693,461	2,810,191	1,258	1,296	5
10,496	10,507	360	370	6
				7
				8
				9
6,218,801	6,531,904	170,020	171,011	10
2,482,185	5,462,029	44	57	11
8,700,986	11,993,933	170,064	171,068	12
				13
8,700,986	11,993,933	170,064	171,068	14

Line 12, column (b) includes $ -4,119,500 of unbilled revenues.

Line 12, column (d) includes -68,689 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 10 Column: b

Detail of Unmetered Sales:

	Revenue	MWH	Average Customers
Residential	5,434,080	26,383	39,451
Commercial	2,477,744	15,188	7,071
Industrial	132,607	895	250
Public Street Lighting	27,993	113	37
Total	8,072,424	42,579	46,809

Schedule Page: 300 Line No.: 10 Column: c

Detail of Unmetered Sales:

	Revenue	MWH	Average Customers
Residential	5,456,659	26,538	39,738
Commercial	2,539,384	15,315	7,122
Industrial	136,852	917	255
Public Street Lighting	27,912	114	37
Total	8,160,807	42,884	47,152

Schedule Page: 300 Line No.: 17 Column: b

Customer Service Revenues (1)	$	496,355
All other under $25,000 each		13,556
	$	509,911

(1) - Includes customer connects, reconnects, disconnects, temporary services and other charges billed to customers.

Schedule Page: 300 Line No.: 17 Column: c

Customer Service Revenues (1)	$	377,271
All other under $25,000 each		13,556
	$	390,827

(1) - Includes customer connects, reconnects, disconnects, temporary services and other charges billed to customers.

Schedule Page: 300 Line No.: 21 Column: b

Description	**YTD**
Oth Elec Rev - Demand Side Management Program	4,348,399
Other Electric Revenues - ABD	229,446
All Other (under $250,000)	85,327
	4,663,172

Schedule Page: 300 Line No.: 21 Column: c

Description	**YTD**
Oth Elec Rev - Demand Side Management Program	5,060,472
Other Electric Revenues - ABD	232,194
All Other (under $250,000)	36,986

5,329,652

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 Residential Sales					
2	Residential Service	2,200,795	214,125,551	137,844	15,966	0.0973
3	Res Service Load Management	2,240	190,973	91	24,615	0.0853
4	Residential Service TOD	45	4,192	3	15,000	0.0932
5	Small General Service	47	5,628	6	7,833	0.1197
6	Revenue Refund		10,426,656			
7	Kentucky Rider		259,945			
8	All Outdoor Lighting	26,383	5,434,080			0.2060
9	Subtotal Billed	2,229,510	230,447,025	137,944	16,162	0.1034
10	Unbilled Revenue	-37,384	-2,508,709			0.0671
11	Total Residential	2,192,126	227,938,316	137,944	15,891	0.1040
12						
13	442 Commercial Sales					
14	Small General Service	135,330	18,331,049	22,851	5,922	0.1355
15	Medium General Service	461,371	51,833,235	6,745	68,402	0.1123
16	Medium General Service TOD	3,633	356,928	76	47,803	0.0982
17	Large General Service	492,510	47,198,377	680	724,279	0.0958
18	Industrial General Service	177,671	11,105,004	24	7,402,958	0.0625
19	All Outdoor Lighting	15,188	2,477,744			0.1631
20	Public Schools	47,993	4,973,996	72	666,569	0.1036
21	Kentucky Rider		-769,336			
22	Mark West HC	2,283	207,551	10	228,300	0.0909
23	Revenue Refund		6,502,780			
24	Estimated Revenue	-116	-12,532			0.1080
25	Subtotal Billed	1,335,863	142,204,796	30,458	43,859	0.1065
26	Unbilled Revenue	-13,145	-809,153			0.0616
27	Total Commercial	1,322,718	141,395,643	30,458	43,428	0.1069
28						
29	442 Industrial Sales					
30	Industrial General Service	2,542,276	136,301,307	63	40,353,587	0.0536
31	Small General Service	4,898	625,358	729	6,719	0.1277
32	Medium General Service	25,366	2,812,774	332	76,404	0.1109
33	Large General Service	125,170	12,150,384	134	934,104	0.0971
34	Revenue Refund		14,132,710			
35	Kentucky Rider		-105,562			
36	All Outdoor Lighting	895	132,607			0.1482
37	Estimated Revenue	13,003	676,802			0.0520
38	Subtotal Billed	2,711,608	166,726,380	1,258	2,155,491	0.0615
39	Unbilled Revenue	-18,147	-800,985			0.0441
40	Total Industrial	2,693,461	165,925,395	1,258	2,141,066	0.0616
41	TOTAL Billed	6,287,490	541,175,312	170,020	36,981	0.0861
42	Total Unbilled Rev.(See Instr. 6)	-68,689	-4,119,500	0	0	0.0600
43	TOTAL	6,218,801	537,055,812	170,020	36,577	0.0864

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3						
4						
5						
6						
7	444 Public Street Lighting					
8	Small General Service	704	134,269	293	2,403	0.1907
9	Medium General Service	1,138	122,039	11	103,455	0.1072
10	Street Lighting	8,559	1,466,780	56	152,839	0.1714
11	Kentucky Rider		-8,419			
12	Revenue Refund		54,449			
13	All Outdoor Lighting	113	27,993			0.2477
14	Subtotal Billed	10,514	1,797,111	360	29,206	0.1709
15	Unbilled Revenue	-18	-653			0.0363
16	Total Public Street Lighting	10,496	1,796,458	360	29,156	0.1712
17						
18	Instruction 5. (See Footnote)					
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	6,287,490	541,175,312	170,020	36,981	0.0861
42	Total Unbilled Rev.(See Instr. 6)	-68,689	-4,119,500	0	0	0.0600
43	TOTAL	6,218,801	537,055,812	170,020	36,577	0.0864

Schedule Page: 304.1 Line No.: 18 Column: a

FUEL CLAUSE

440 RESIDENTIAL SALES	
Residential Service	$ (13,666,684)
Residential Load Management	(14,169)
Residential Service TOD	(269)
Small General Service	(291)
All Outdoor Lighting	(163,734)
Unbilled Revenue	(281,925)
TOTAL RESIDENTIAL	(14,127,072)
442 COMMERCIAL SALES	
Public Schools	(306,542)
Mark West HC	(13,696)
Industrial General Service	(1,079,709)
Large General Service	(2,978,004)
Medium General Service	(2,814,889)
Medium General Service TOD	(22,389)
Small General Service	(832,069)
All Outdoor Lighting	(94,794)
Estimated Billings	(2,969)
Unbilled Revenue	(174,045)
TOTAL COMMERCIAL	(8,319,106)
442 INDUSTRIAL SERVICE	
Industrial General Company	(15,312,152)
Large General Service	(756,220)
Medium General Service	(155,938)
Small General Service	(29,771)
All Outdoor Lighting	(5,539)
Estimated Billings	(143,610)
Unbilled Revenue	(97,476)
TOTAL INDUSTRIAL	(16,500,706)
444 PUBLIC STREET LIGHTING	
Small General Service	(4,321)
Medium General Service	(7,017)
Street Lighting	(52,687)
All Outdoor Lighting	(701)
Unbilled Revenue	(372)
TOTAL PUBLIC STREET LIGHTING	(65,098)
445 PUBLIC SCHOOLS	
Public Schools	-
Unbilled Revenue	-
TOTAL PUBLIC SCHOOLS	-
TOTAL FUEL CLAUSE	$ (39,011,982)

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	CITY OF OLIVE HILL	RQ	KPCO 52			
2	CITY OF VANCEBURG	RQ	KPCO 51			
3	PJM TRANSMISSION FOR RQ	RQ	Various			
4	ADVAN PROMOTIONS INC.	OS	Note 1			
5	AMEREN CILCO	OS	Note 1			
6	AMEREN ENERGY MARKETING	OS	Note 1			
7	AMEREN ILLINOIS COMPANY	OS	Note 1			
8	AMERICAN MUNICIPAL POWER - OHIO	OS	Note 1			
9	B.P. ENERGY COMPANY	OS	Note 1			
10	CITIGROUP ENERGY INC.	OS	Note 1			
11	CITY OF BANGOR, WISCONSIN	OS	Note 1			
12	CITY OF BARRON, WISCONSIN	OS	Note 1			
13	CITY OF BLOOMER, WISCONSIN	OS	Note 1			
14	CITY OF COLUMBUS	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	CITY OF CORNELL, WISCONSIN	OS	Note 1			
2	CITY OF MEDFORD	OS	Note 1			
3	CITY OF RICE LAKE UTILITIES	OS	Note 1			
4	CITY OF SHELBY	OS	Note 1			
5	CITY OF SPOONER, WISCONSIN	OS	Note 1			
6	CITY OF WAKEFIELD, WISCONSIN	OS	Note 1			
7	CITY OF WESTERVILLE	OS	Note 1			
8	COMMONWEALTH EDISON COMPANY	OS	Note 1			
9	CONOCO INC.	OS	Note 1			
10	COOK INLET ENERGY SUPPLY LP	OS	Note 1			
11	DAIRYLAND POWER COOPERATIVE	OS	Note 1			
12	DTE ENERGY TRADING INC.	OS	Note 1			
13	DUKE ENERGY KENTUCKY, INC.	OS	Note 1			
14	DUKE ENERGY OHIO, INC	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	DUQUESNE LIGHT COMPANY	OS	Note 1			
2	DYNEGY POWER MARKETING INC.	OS	Note 1			
3	EDF TRADING NORTH AMERICA LLC	OS	Note 1			
4	ENDURE ENERGY, LLC	OS	Note 1			
5	ENERGY AMERICA, LLC	OS	Note 1			
6	EXELON GENERATION - POWER TEAM	OS	Note 1			
7	HARRISON RURAL ELECTRIFICATION	OS	Note 1			
8	INDIANA MUNICIPAL POWER AGENCY	OS	Note 1			
9	JP MORGAN VENTURES ENERGY CORP	OS	Note 1			
10	LG&E UTILITIES POWER SALES	OS	Note 1			
11	METROPOLITAN EDISON COMPANY	OS	Note 1			
12	MIDWEST ISO	OS	Note 1			
13	MIZUHO SECURITIES USA INC	OS	Note 1			
14	MORGAN STANLEY CAPT.	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	NC ELECTRIC MEMBERSHIP CORP.	OS	Note 1			
2	NEXTERA ENERGY POWER MKTG LLC	OS	Note 1			
3	NOBLE AMERICAS GAS AND POWER	OS	Note 1			
4	OHIO POWER COMPANY (AUCTION)	OS	Note 1			
5	PENNSYLVANIA ELECTRIC COMPANY	OS	Note 1			
6	PJM INTERCONNECTION	OS	Note 1			
7	RBC CAPITAL MARKET, LLC	OS	Note 1			
8	SOUTHERN COMPANY	OS	Note 1			
9	SUNCOKE ENERGY, INC.	OS	Note 1			
10	THE BOROUGH OF PITCAIRN, PA	OS	Note 1			
11	THE ENERGY AUTHORITY	OS	Note 1			
12	TIMBER CANYON	OS	Note 1			
13	TOWN OF HAGERSTOWN, INDIANA	OS	Note 1			
14	TVA BULK POWER TRADING	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	UBS AG, LONDON BRANCH	OS	Note 1			
2	UNION ELECTRIC COMPANY	OS	Note 1			
3	VILLAGE OF BETHEL OHIO	OS	Note 1			
4	VILLAGE OF CADOTT, WISCONSIN	OS	Note 1			
5	VILLAGE OF GLOUSTER	OS	Note 1			
6	VILLAGE OF HAMERSVILLE, OHIO	OS	Note 1			
7	VILLAGE OF RIPLEY OHIO	OS	Note 1			
8	VILLAGE OF TREMPEALEAU, WISCONSIN	OS	Note 1			
9	WEST PENN POWER COMPANY	OS	Note 1			
10	WESTAR ENERGY INC.	OS	Note 1			
11	WOLVERINE POWER SUPPLY COOP	OS	Note 1			
12	WPPI ENERGY	OS	Note 1			
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
24,200	1,570,324	1,153,708		2,724,032	1
65,737	3,934,687	2,722,463		6,657,150	2
			-1,078,801	-1,078,801	3
		-1,025		-1,025	4
		-1,212		-1,212	5
		7		7	6
15,798		579,958		579,958	7
7,303		434,384		434,384	8
	5,643	-95,628		-89,985	9
		-222		-222	10
1,739		110,876		110,876	11
5,043		314,037		314,037	12
3,496		218,622		218,622	13
		-2,473		-2,473	14
89,937	5,505,011	3,876,171	-1,078,801	8,302,381	
2,392,248	914,349	87,610,312	0	88,524,661	
2,482,185	**6,419,360**	**91,486,483**	**-1,078,801**	**96,827,042**	

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
826		51,963		51,963	1
8,111		496,211		496,211	2
10,369		658,878		658,878	3
1		354		354	4
1,953		123,542		123,542	5
864		52,679		52,679	6
30,171		2,400,728		2,400,728	7
7,593		269,971		269,971	8
		-35,886		-35,886	9
		-526,424		-526,424	10
		-10,495		-10,495	11
		-107		-107	12
	13,042			13,042	13
35,736		2,141,910		2,141,910	14
89,937	5,505,011	3,876,171	-1,078,801	8,302,381	
2,392,248	914,349	87,610,312	0	88,524,661	
2,482,185	**6,419,360**	**91,486,483**	**-1,078,801**	**96,827,042**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
102,901		6,123,993		6,123,993	1
		69,597		69,597	2
	-21			-21	3
		141		141	4
		30,752		30,752	5
-2,584		-356,670		-356,670	6
3,440		250,725		250,725	7
	12,308			12,308	8
		-642,641		-642,641	9
-2,065		-80,799		-80,799	10
4,335		335,077		335,077	11
-74,497		-2,394,965		-2,394,965	12
		62,966		62,966	13
602		-481,291		-481,291	14
89,937	5,505,011	3,876,171	-1,078,801	8,302,381	
2,392,248	914,349	87,610,312	0	88,524,661	
2,482,185	**6,419,360**	**91,486,483**	**-1,078,801**	**96,827,042**	

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
54,925		2,482,619		2,482,619	1
	8,229			8,229	2
-404		-11,591		-11,591	3
76,653		4,182,529		4,182,529	4
6,708		484,071		484,071	5
2,086,302	797,481	67,774,131		68,571,612	6
	-186	1,192,317		1,192,131	7
2,209		72,266		72,266	8
	77,853			77,853	9
		812		812	10
58		1,499		1,499	11
		-1,025		-1,025	12
1,459		92,475		92,475	13
-37,395		-626,281		-626,281	14
89,937	5,505,011	3,876,171	-1,078,801	8,302,381	
2,392,248	914,349	87,610,312	0	88,524,661	
2,482,185	**6,419,360**	**91,486,483**	**-1,078,801**	**96,827,042**	

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
		-4,417		-4,417	1
		-15,624		-15,624	2
14		640		640	3
883		56,641		56,641	4
		48		48	5
6		303		303	6
15		719		719	7
976		63,286		63,286	8
11,198		751,831		751,831	9
43		-10,575		-10,575	10
27,463		1,035,340		1,035,340	11
		-9,235		-9,235	12
					13
					14
89,937	5,505,011	3,876,171	-1,078,801	8,302,381	
2,392,248	914,349	87,610,312	0	88,524,661	
2,482,185	**6,419,360**	**91,486,483**	**-1,078,801**	**96,827,042**	

Schedule Page: 310 Line No.: 1 Column: k

Margins for Off System Sales (OSS) reported in KPCO's generation formula rates are included in the total revenue amount. The margins are specifically identified in the ledger as a subset of the accounts that make up these OSS revenues.

Schedule Page: 310 Line No.: 3 Column: j

Amount represents transmission services and related charges.

Schedule Page: 310 Line No.: 4 Column: c

NOTE 1: FERC Electric Tariff, First Revised Volume No. 5.

Schedule Page: 310.3 Line No.: 4 Column: a

An affiliated company.

Schedule Page: 310.3 Line No.: 4 Column: c

The PUCO (Public Utilities Commission Ohio) ordered OPCo to conduct energy and capacity auctions for its entire SSO load for delivery beginning June 2015. APCo, KPCo, I&M and WPCo participated in the auction process and were awarded tranches of OPCo's SSO load.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	3,605,877	3,922,152
5	(501) Fuel	158,233,198	266,538,733
6	(502) Steam Expenses	8,364,443	11,236,340
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	235,733	494,139
10	(506) Miscellaneous Steam Power Expenses	5,886,357	11,606,658
11	(507) Rents		
12	(509) Allowances	2,378,334	8,383,511
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	178,703,942	302,181,533
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	3,318,034	3,717,115
16	(511) Maintenance of Structures	2,899,883	1,771,951
17	(512) Maintenance of Boiler Plant	18,164,423	18,592,358
18	(513) Maintenance of Electric Plant	6,333,300	3,316,482
19	(514) Maintenance of Miscellaneous Steam Plant	1,643,296	1,655,856
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	32,358,936	29,053,762
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	211,062,878	331,235,295
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		
64	(548) Generation Expenses		
65	(549) Miscellaneous Other Power Generation Expenses		
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)		
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)		
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)		
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	155,502,301	163,908,718
77	(556) System Control and Load Dispatching	478,465	507,760
78	(557) Other Expenses	1,698,481	1,851,763
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	157,679,247	166,268,241
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	368,742,125	497,503,536
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,137,188	1,151,779
84			
85	(561.1) Load Dispatch-Reliability	5,632	7,564
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	820,159	877,641
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	1,232,355	1,193,916
89	(561.5) Reliability, Planning and Standards Development	139,836	116,087
90	(561.6) Transmission Service Studies	110	
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	305,965	279,976
93	(562) Station Expenses	464,602	420,574
94	(563) Overhead Lines Expenses	163,797	126,823
95	(564) Underground Lines Expenses	-7	7
96	(565) Transmission of Electricity by Others	18,972,154	12,040,231
97	(566) Miscellaneous Transmission Expenses	1,204,474	1,411,123
98	(567) Rents	13,363	250
99	TOTAL Operation (Enter Total of lines 83 thru 98)	24,459,628	17,625,971
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	27,593	86,758
102	(569) Maintenance of Structures	4,918	28,532
103	(569.1) Maintenance of Computer Hardware	589	19,165
104	(569.2) Maintenance of Computer Software	79,679	296,955
105	(569.3) Maintenance of Communication Equipment	1,896	15,528
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	663,400	859,349
108	(571) Maintenance of Overhead Lines	2,298,682	2,923,424
109	(572) Maintenance of Underground Lines	206	81
110	(573) Maintenance of Miscellaneous Transmission Plant	298,049	209,415
111	TOTAL Maintenance (Total of lines 101 thru 110)	3,375,012	4,439,207
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	27,834,640	22,065,178

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	1,015,045	1,263,004
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	1,015,045	1,263,004
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	1,015,045	1,263,004
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	642,645	605,349
135	(581) Load Dispatching	3,544	3,108
136	(582) Station Expenses	184,894	181,103
137	(583) Overhead Line Expenses	397,866	1,191,000
138	(584) Underground Line Expenses	101,171	107,731
139	(585) Street Lighting and Signal System Expenses	190,231	158,486
140	(586) Meter Expenses	811,607	781,773
141	(587) Customer Installations Expenses	149,576	192,660
142	(588) Miscellaneous Expenses	4,685,951	3,764,860
143	(589) Rents	1,514,941	1,719,024
144	TOTAL Operation (Enter Total of lines 134 thru 143)	8,682,426	8,705,094
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	702	1,791
147	(591) Maintenance of Structures	9,088	20,906
148	(592) Maintenance of Station Equipment	540,532	648,411
149	(593) Maintenance of Overhead Lines	37,695,498	35,149,543
150	(594) Maintenance of Underground Lines	112,365	101,646
151	(595) Maintenance of Line Transformers	71,015	61,842
152	(596) Maintenance of Street Lighting and Signal Systems	63,729	58,723
153	(597) Maintenance of Meters	115,431	107,091
154	(598) Maintenance of Miscellaneous Distribution Plant	79,935	193,759
155	TOTAL Maintenance (Total of lines 146 thru 154)	38,688,295	36,343,712
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	47,370,721	45,048,806
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	236,292	287,039
160	(902) Meter Reading Expenses	539,951	600,684
161	(903) Customer Records and Collection Expenses	5,081,975	5,299,254
162	(904) Uncollectible Accounts	249,840	-11,198
163	(905) Miscellaneous Customer Accounts Expenses	22,828	25,042
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	6,130,886	6,200,821

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	99,216	162,288
168	(908) Customer Assistance Expenses	3,592,792	4,636,865
169	(909) Informational and Instructional Expenses	122,684	76,330
170	(910) Miscellaneous Customer Service and Informational Expenses	93,912	62,617
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	3,908,604	4,938,100
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	458	
175	(912) Demonstrating and Selling Expenses	46,255	53,656
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	46,713	53,656
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	8,467,676	9,261,125
182	(921) Office Supplies and Expenses	655,751	603,230
183	(Less) (922) Administrative Expenses Transferred-Credit	1,262,010	1,105,695
184	(923) Outside Services Employed	2,206,062	2,254,668
185	(924) Property Insurance	597,561	534,909
186	(925) Injuries and Damages	2,197,102	1,555,922
187	(926) Employee Pensions and Benefits	4,197,814	4,874,031
188	(927) Franchise Requirements	135,352	142,389
189	(928) Regulatory Commission Expenses	2,034,798	814,167
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	106,815	84,416
192	(930.2) Miscellaneous General Expenses	355,929	430,961
193	(931) Rents	386,954	375,764
194	TOTAL Operation (Enter Total of lines 181 thru 193)	20,079,804	19,825,887
195	Maintenance		
196	(935) Maintenance of General Plant	2,534,847	1,975,632
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	22,614,651	21,801,519
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	477,663,385	598,874,620

Schedule Page: 320 Line No.: 5 Column: b

The portion of account 501 that is excluded from the fuel costs in KPCo's generation formula rate is identified by a query of the general ledger.

Schedule Page: 320 Line No.: 93 Column: b

Generation Step-Up Units' (GSUs) O&M expenses included in KPCo's generation formula rates are the ratio of GSU balances to all investment for plant accounts 352 & 353 multiplied by the balance in O&M accounts 562, 569 & 570.

Schedule Page: 320 Line No.: 185 Column: b

The insurance expenses for generation included in KPCO's generation formula rate are identified by a query of the general ledger.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	AEP GENERATING COMPANY	RQ	AEG 2			
2	CMS MARKETING SVCS AND TRADING	OS				
3	DYNEGY POWER MARKETING INC.	OS				
4	EDF TRADING NORTH AMERICA LLC	OS				
5	JP MORGAN VENTURES ENERGY CORP	OS				
6	KY ENVIRONMENTAL SURCHARGE RIDER	OS				
7	PJM INTERCONNECTION	OS				
8	PJM OVER/UNDER RECOVERY	OS				
9	PURCHASED POWER ADJUSTMENT	OS				
10						
11						
12						
13						
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1,866,893			51,535,208	47,939,637		99,474,845	1
			29,214			29,214	2
			110			110	3
			-19,266			-19,266	4
			50,235			50,235	5
				-1,310,599		-1,310,599	6
1,423,433			1,620,195	55,998,140		57,618,335	7
				-107,943		-107,943	8
				-232,630		-232,630	9
							10
							11
							12
							13
							14
3,290,326			53,215,696	102,286,605		155,502,301	

Name of Respondent Kentucky Power Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4

FOOTNOTE DATA

Schedule Page: 326 Line No.: 1 Column: a

Affiliated Company

Schedule Page: 326 Line No.: 6 Column: a

Over/under accounting for the KY environmental surcharge. KPSC Order Case No. 2014-00396

Schedule Page: 326 Line No.: 8 Column: a

KPSC Order Case No. 2014-00396. Commission approved recovery of Big Sandy U1 non fuel operating costs as a coal burning unit and costs associated with its conversion to natural gas. AEP gets a return of the capital investment once the gas unit goes into service.

Schedule Page: 326 Line No.: 9 Column: a

Deferral to track over/under of permitted Purchase Power costs in KYP (not included in the KYP FAC), in accordance with the Stipluation and Settlement Agreement approved in KYP Case No. 2012-00578.

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	PJM Network Integ Trans Rev Whlsle	Various	Various	FNO
2	PJM Network Integ Trans Serv	Various	Various	FNO
3	PJM Trans Enhancement Rev	Various	Various	FNO
4	PJM Trans Enhancement Rev - Affil	Various	Various	FNS
5	PJM Trans Enhancement Rev Whlsle	Various	Various	FNO
6	PJM Network Integ Rev - Affil	Various	Various	FNS
7	PJM Point to Point Trans Serv	Various	Various	LFP
8	PJM Trans Owner Admin Revenue	Various	Various	OLF
9	PJM Trans Owner Serv Rev Whlsle	Various	Various	OLF
10	PJM Expansion Cost Recovery	Various	Various	OS
11	PJM Power Factor Credits Rev Whlsle	Various	Various	OS
12	RTO Formation Costs Recovery	Various	Various	OS
13	PJM Trans Owner Serv - Affil	Various	Various	OLF
14	East Kentucky Power Cooperative	Various	Various	OLF
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
PJM OATT	Various	Various				1
PJM OATT	Various	Various				2
PJM OATT	Various	Various				3
PJM OATT	Various	Various				4
PJM OATT	Various	Various				5
PJM OATT	Various	Various				6
PJM OATT	Various	Various				7
PJM OATT	Various	Various				8
PJM OATT	Various	Various				9
PJM OATT	Various	Various				10
PJM OATT	Various	Various				11
PJM OATT	Various	Various				12
PJM OATT	Various	Various				13
See Footnote	Various	Various		36,732	36,732	14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	**36,732**	**36,732**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
2,541,659			2,541,659	1
10,094,641			10,094,641	2
791,410			791,410	3
132,200			132,200	4
45,123			45,123	5
7,026,580			7,026,580	6
600,207			600,207	7
	230,651		230,651	8
	51,231		51,231	9
25,366			25,366	10
		6,770	6,770	11
37,483			37,483	12
	118,119		118,119	13
		55,098	55,098	14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
21,294,669	**400,001**	**61,868**	**21,756,538**	

Schedule Page: 328 Line No.: 1 Column: e

Effective October 1, 2004, the administration of the transmission tariff was turned over to PJM. PJM does not provide any detail except for the total revenue by major classes listed. OATT (Open Access Transmission Tariff) 3rd Revised Volume No. 6.

Schedule Page: 328 Line No.: 11 Column: m

Per Proforma ILDSA (Interconnection and Local Delivery Service Agreement) AEP Tariff 3rd Revised Volume No.6.

Schedule Page: 328 Line No.: 14 Column: e

Compensation shall be at a rate of one and one-half (1.5) mills per kilowatt-hour for energy delivered pursuant to Appendix IV of PJM Service Agreement No. 1530, the Interconnection Agreement between AEPSC and East Kentucky Power Cooperative.

Schedule Page: 328 Line No.: 14 Column: m

Compensation shall be at a rate of one and one-half (1.5) mills per kilowatt-hour for energy delivered pursuant to Appendix IV of PJM Service Agreement No. 1530, the Interconnection Agreement between AEPSC and East Kentucky Power Cooperative.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Concurrent Energy	LFP	95,081	95,081			142,621	142,621
2	East KY Power Coop							
3	PJM - Enhancements	OS					7,310,396	7,310,396
4	PJM - NITS	OS					11,477,623	11,477,623
5	PJM - Trans Owner	OS					41,451	41,451
6	Other	OS					63	63
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		95,081	95,081			18,972,154	18,972,154

Schedule Page: 332 Line No.: 1 Column: g

Compensation shall be at a rate of one and one-half (1.5) mills per kilowatt-hour for energy delivered pursuant to Appendix IV of PJM Service Agreement No. 1530, the Interconnection Agreement between AEPSC and East Kentucky Power Cooperative.

Schedule Page: 332 Line No.: 3 Column: a

Transmission Enhancement Charges and Credits (PJM OATT Schedule 12).

Schedule Page: 332 Line No.: 4 Column: a

Network Integration Transmission Service Charges - NITS (PJM OATT Schedule H).

Schedule Page: 332 Line No.: 5 Column: a

Transmission Owner Charges and Credits (PJM OATT Tariff Sixth Revised Volume No. 1).

Schedule Page: 332 Line No.: 6 Column: a

Midwest Independent Transmission System Operator (MISO) Membership/Participant Dues.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	100,303
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	2,485
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	18,410
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Associated Business Development	148,262
7	AEP Service Corporation Billings	64,467
8	Intercompany Allocations	-18,518
9	Corporate Money Pool Allocations	13,062
10	Misc Marketing Expenses	5,796
11	Miscellaneous	21,662
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	355,929

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			3,726,425		3,726,425
2	Steam Production Plant	42,398,274	344,928	389,102		43,132,304
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant					
7	Transmission Plant	12,367,308				12,367,308
8	Distribution Plant	26,054,977				26,054,977
9	Regional Transmission and Market Operation					
10	General Plant	1,270,348		89,108		1,359,456
11	Common Plant-Electric					
12	TOTAL	82,090,907	344,928	4,204,635		86,640,470

B. Basis for Amortization Charges

Section A, Line 1, Column D represents amortization of franchises over the life of the franchise ($400) and amortization of capitalized software development costs over a 5 year life ($3,726,025).

Section A, Line 2, Column D represents amortization of Selective Catalytic Reduction catalyst equipment over a useful life range defined as:

SCR Catalyst Layer 1 (15 years) = ($217,405)
SCR Catalyst Layer 2 (19 years) = ($171,697)

Total = ($389,102)

Section A, Line 10, Column D represents amortization of Leasehold improvements over the term of the lease for the respective building.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	STEAM GENERATION						
13	311 - Big Sandy	9,240			3.78		
14	311 - Gypsum Unloader	11		5.00	2.66		
15	311 - Mitchell	52,030		5.00	2.66		
16	312 - Big Sandy	15,139			3.78		
17	312 - Gypsum Unloader	6,605		5.00	3.05		
18	312 - Mitchell	850,298		5.00	3.05		
19	312 - Mitchell SCR	8,190		5.00	12.50		
20	314 - Big Sandy	61,265			3.78		
21	314 - Mitchell	53,897		5.00	1.76		
22	315 - Big Sandy	3,759			3.78		
23	315 - Mitchell	24,584		5.00	1.56		
24	316 - Big Sandy	2,854			3.78		
25	316 - Mitchell	7,910		5.00	2.72		
26	TOTAL STEAM	1,095,782					
27							
28	TRANSMISSION						
29	350 (Rights)	31,633	75.00		1.44	R4	
30	352	6,611	60.00	10.00	2.08	S3	
31	352 - Big Sandy	10	60.00	10.00	2.08	S3	
32	352 - Mitchell	72	60.00	10.00	2.08	S3	
33	353	183,488	50.00	3.00	2.15	L0.5	
34	353 - Big Sandy	603	50.00	3.00	2.15	L0.5	
35	353 - Mitchell	9,513	50.00	3.00	2.15	L0.5	
36	354	94,978	51.00	10.00	2.61	S6	
37	355	97,906	43.00	61.00	3.95	L3	
38	356	136,484	50.00	27.00	2.91	S6	
39	357	12	37.00		2.99	R2	
40	358	106	44.00		2.62	R1	
41	TOTAL TRANSMISSION	561,416					
42							
43	DISTRIBUTION						
44	360 (Rights)	5,346	75.00		3.52	R4	
45	361	4,383	65.00		3.52	L0.5	
46	362	93,228	25.00	-25.00	3.52	L0	
47	364	192,476	28.00		3.52	L0	
48	365	205,139	26.00	-25.00	3.52	R1.5	
49	366	6,920	37.00		3.52	R2	
50	367	10,697	44.00		3.52	R1	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	368	126,745	25.00	-15.00	3.52	R1.5	
13	369	57,622	18.00		3.52	R2	
14	370	24,924	27.00		3.52	R0.5	
15	371	19,818	11.00	-30.00	3.52	L0	
16	373	3,575	15.00	-15.00	3.52	L0	
17	TOTAL DISTRIBUTION	750,873					
18							
19	GENERAL PLANT						
20	389.1	37	75.00		1.59	R4	
21	390	20,373	35.00		3.97	L2	
22	391	1,683	35.00		3.20	SQ	
23	392	15	30.00		3.52	SQ	
24	393	165	30.00		4.15	SQ	
25	394	3,877	30.00	9.00	4.20	SQ	
26	395	209	30.00		5.76	SQ	
27	396	6	25.00		5.43	SQ	
28	397	7,090	22.00	-3.00	5.66	SQ	
29	397.16	1,091	22.00	-3.00	5.66	SQ	
30	398	1,618	20.00	3.00	6.73	SQ	
31	TOTAL GENERAL	36,164					
32							
33	DEPRECIABLE SUM	2,444,235					
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							
49							
50							

Schedule Page: 336 Line No.: 7 Column: b

Generation Step-up Units' (GSU's) depreciation expenses included in KPCo's generation
formula rates are a subset of transmission depreciation and identified by a query of the
plant accounting system.

Schedule Page: 336.1 Line No.: 33 Column: b

The depreciable plant base is the November 30, 2015 total company depreciable plant.

In May 2015, AEP retired Big Sandy Unit 2 from its fleet.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	2014 Kentucky Power Base Case		1,966,240	1,966,240	
2	KPSC - Case No. 2014-00396				
3					
4	FERC Filings Case Support		40,805	40,805	
5					
6	2014 Environmental Compliance Plan		39,869	39,869	
7					
8	Miscellaneous		-12,116	-12,116	
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL		2,034,798	2,034,798	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
	928	1,966,240					1
							2
							3
	928	40,805					4
							5
	928	39,869					6
							7
	928	-12,116					8
							9
							10
							11
							12
							13
							14
							15
							16
							17
							18
							19
							20
							21
							22
							23
							24
							25
							26
							27
							28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		2,034,798					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A(1)b: Generation: Fossil-Fuel Steam	Generation Asset Management - Program Management
2		3 items under $50,000
3		
4	A(1)e: Generation: Unconventional	1 item under $50,000
5		2 items under $50,000
6		
7	A(2): Transmission	2 items under $50,000
8		
9	A(3): Distribution	1 item under $50,000
10		
11	A(5): Environment (other than equipment)	Carbon Management - University of Kentucky Research Foundation
12		3 item under $50,000
13		
14	A(6): Other	3 items under $50,000
15		3 items under $50,000
16		4 items under $50,000
17		
18	A(6)f: Other (Metering)	1 item under $50,000
19		
20	A(6)g: Other (program management)	1 item under $50,000
21		1 item under $50,000
22		
23	B: Electric R&D External	1 item under $50,000
24		3 items under $50,000
25		4 items under $50,000
26		
27	B(1): R&D support to the Research Council	EPRI Environmental Controls
28	or the Electric Power Research	EPRI Environmental Science
29	Institute	21 items under $50,000
30		13 items under $50,000
31		8 items under $50,000
32		
33		
34		
35		
36		
37		
38		

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
63,024		506	63,024		1
5,466		506	5,466		2
					3
341		506	341		4
943		588	943		5
					6
1,504		566	1,504		7
					8
2,131		588	2,131		9
					10
200,000		182.3	200,000		11
13,030		506	13,030		12
					13
5,383		506	5,383		14
1,588		566	1,588		15
5,497		588	5,497		16
					17
81		588	81		18
					19
117		566	117		20
170		588	170		21
					22
	2,275	506	2,275		23
	2,755	566	2,755		24
	9,917	588	9,917		25
					26
	141,701	506	141,701		27
	258,073	506	258,073		28
	107,163	506	107,163		29
	49,022	566	49,022		30
	32,358	588	32,358		31
					32
					33
					34
					35
					36
					37
					38

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	7,682,761		
4	Transmission	158		
5	Regional Market			
6	Distribution	3,277,995		
7	Customer Accounts	1,297,828		
8	Customer Service and Informational	595,060		
9	Sales			
10	Administrative and General	773,370		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	13,627,172		
12	Maintenance			
13	Production	10,415,775		
14	Transmission	75,632		
15	Regional Market			
16	Distribution	4,950,448		
17	Administrative and General	733,768		
18	TOTAL Maintenance (Total of lines 13 thru 17)	16,175,623		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	18,098,536		
21	Transmission (Enter Total of lines 4 and 14)	75,790		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	8,228,443		
24	Customer Accounts (Transcribe from line 7)	1,297,828		
25	Customer Service and Informational (Transcribe from line 8)	595,060		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	1,507,138		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	29,802,795	1,799,676	31,602,471
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	29,802,795	1,799,676	31,602,471
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	8,834,496	533,481	9,367,977
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	8,834,496	533,481	9,367,977
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,755,035	166,366	2,921,401
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	2,755,035	166,366	2,921,401
77	Other Accounts (Specify, provide details in footnote):			
78	152 - Fuel Stock Undistributed	3,884,716		3,884,716
79	163 - Stores Expense Undistributed	1,688,308	-1,688,308	
80	184 - Clearing Accounts	811,215	-811,215	
81	185 - ODD Temporary Facilities	35,606		35,606
82	186 - Misc Deferred Debits	155,019		155,019
83	188 - Research & Development	-241		-241
84	426 - Political Activities	47,220		47,220
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	6,621,843	-2,499,523	4,122,320
96	TOTAL SALARIES AND WAGES	48,014,169		48,014,169

Schedule Page: 354   Line No.: 28   Column: b

The labor charges from AEP Service Corporation included in the development of the KPCo generation formula rate payroll allocator is derived from a query of the general ledger.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				46,419,610
3	Net Sales (Account 447)				(90,161,706)
4	Transmission Rights				(8,246,609)
5	Ancillary Services				1,893,608
6	Other Items (list separately)				
7	Congestion				24,707,011
8	Operating Reserves				2,059,116
9	Transmission Purchase Expense				1,098,983
10	Transmission Losses				12,232,664
11	Meter Corrections				918,036
12	Inadvertent				28,698
13	Capacity Credits				(824,141)
14	Miscellaneous				
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				(9,874,730)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch						
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response						
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)						

Schedule Page: 398 Line No.: 1 Column: b

The final grandfathered contracts (under the AEP OATT) expired 12/31/2010. Currently, services are provided under the SPP and PJM OATTs.

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	5,821,424
4	Nuclear	
5	Hydro-Conventional	
6	Hydro-Pumped Storage	
7	Other	
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	5,821,424
10	Purchases	3,290,326
11	Power Exchanges:	
12	Received	
13	Delivered	
14	Net Exchanges (Line 12 minus line 13)	
15	Transmission For Other (Wheeling)	
16	Received	36,732
17	Delivered	36,732
18	Net Transmission for Other (Line 16 minus line 17)	
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	9,111,750

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	6,218,801
23	Requirements Sales for Resale (See instruction 4, page 311.)	89,937
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,392,248
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
27	Total Energy Losses	410,764
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	9,111,750

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	1,175,854	482,432	1,535	8	800
30	February	1,121,834	439,074	1,666	20	800
31	March	823,207	245,552	1,400	6	800
32	April	809,509	333,470	892	1	900
33	May	705,161	191,323	975	27	1700
34	June	620,116	83,024	1,050	23	1600
35	July	795,653	247,829	1,097	29	1700
36	August	769,064	233,656	982	19	1500
37	September	633,948	134,180	1,019	3	1700
38	October	532,467	18,192	894	19	900
39	November	581,455	43,094	1,075	23	800
40	December	543,482	16,482	1,022	4	800
41	TOTAL	9,111,750	2,468,308			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: Big Sandy (b)			Plant Name: Mitchell-KEPCo Share (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	STEAM			STEAM		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	CONVENTIONAL			OUTDOOR BOILER		
3	Year Originally Constructed	1963			1971		
4	Year Last Unit was Installed	1969			1971		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	1096.80			817.00		
6	Net Peak Demand on Plant - MW (60 minutes)	1081			783		
7	Plant Hours Connected to Load	6860			5845		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	1078			780		
10	When Limited by Condenser Water	1078			780		
11	Average Number of Employees	76			116		
12	Net Generation, Exclusive of Plant Use - KWh	3132143000			2689281000		
13	Cost of Plant: Land and Land Rights	1753939			3103945		
14	Structures and Improvements	9232317			52040441		
15	Equipment Costs	83015889			952551970		
16	Asset Retirement Costs	1893267			6129318		
17	Total Cost	95895412			1013825674		
18	Cost per KW of Installed Capacity (line 17/5) Including	87.4320			1240.9127		
19	Production Expenses: Oper, Supv, & Engr	1128067			2477810		
20	Fuel	83244873			75087449		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	1877692			6486751		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	235755			-21		
26	Misc Steam (or Nuclear) Power Expenses	3269077			2617280		
27	Rents	0			0		
28	Allowances	2038347			339987		
29	Maintenance Supervision and Engineering	1617214			1700819		
30	Maintenance of Structures	2306383			593499		
31	Maintenance of Boiler (or reactor) Plant	4012683			14151740		
32	Maintenance of Electric Plant	2117095			4216206		
33	Maintenance of Misc Steam (or Nuclear) Plant	966103			677193		
34	Total Production Expenses	102813289			108348713		
35	Expenses per Net KWh	0.0328			0.0403		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	COAL	OIL		COAL	OIL	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	TONS	BARRELS		TONS	BARRELS	
38	Quantity (Units) of Fuel Burned	1282675	9628	0	1118608	31543	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11053	136606	0	12294	136909	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	60.469	63.187	0.000	61.388	78.872	0.000
41	Average Cost of Fuel per Unit Burned	64.014	99.604	0.000	64.401	97.369	0.000
42	Average Cost of Fuel Burned per Million BTU	2.896	17.360	0.000	2.619	16.933	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.026	0.000	0.000	0.027	0.000	0.000
44	Average BTU per KWh Net Generation	8899.000	0.000	0.000	10291.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Mitchell- Total* (d)			Plant Name: (e)			Plant Name: (f)			Line No.
		STEAM							1
		OUTDOOR BOILER							2
		1971							3
		1971							4
		1633.00			0.00			0.00	5
		1567			0			0	6
		5845			0			0	7
		0			0			0	8
		1560			0			0	9
		1560			0			0	10
		232			0			0	11
		4983272000			0			0	12
		6207890			0			0	13
		103922266			0			0	14
		1903319458			0			0	15
		10549165			0			0	16
		2023998779			0			0	17
		1239.4359			0			0	18
		4409296			0			0	19
		126439740			0			0	20
		0			0			0	21
		11590333			0			0	22
		0			0			0	23
		0			0			0	24
		-317			0			0	25
		5938260			0			0	26
		0			0			0	27
		340752			0			0	28
		3195667			0			0	29
		1265670			0			0	30
		29445783			0			0	31
		8237812			0			0	32
		1310009			0			0	33
		192173005			0			0	34
		0.0386			0.0000			0.0000	35
COAL	OIL								36
TONS	BARRELS								37
2078284	61070	0	0	0	0	0	0	0	38
12294	136909	0	0	0	0	0	0	0	39
61.524	78.891	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
63.585	96.755	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
2.586	16.826	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.027	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
10291.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Schedule Page: 402 Line No.: -1 Column: b

Big Sandy Plant Unit 2: Kentucky Power Company retired this Unit May 31, 2015. Lines 13-17 do not include Big Sandy Unit 2 data. Lines 19-34 include Big Sandy Unit 2 expense data prior to retirement.

Schedule Page: 402 Line No.: -1 Column: c

Plant Name: Mitchell - This plant is owned jointly by Respondent and Wheeling Power Company, also a subsidary of American Electric Power,Inc. Included in Mitchell Plant's investment are costs of $10,826(structures and improvements)and $6,604,781(equipment). These amounts were paid by Kentucky Power Company in gypsum unloading equipment located at Mountaineer Plant, which is owned and operated by Appalachian Power Company, a subsidiary of American Electric Power Inc.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. 0 Plant Name: (c)	FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			29
			30
			31
			32
			33
			34
			35
			36
			37
			38

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42
						43
						44
						45
						46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1	0700 BIG SANDY, KY	AMOS WV	765.00	765.00	ST	0.13		1
2	0701 BIG SANDY, KY	SARGENTS, OH	765.00	765.00	ALUM	24.20		1
3	0701 BIG SANDY, KY	SARGENTS, OH	765.00	765.00	ST	4.79		1
4	0702 BIG SANDY, KY	BROADFORD, VA	765.00	765.00	ALUM	12.65		1
5	0702 BIG SANDY, KY	BROADFORD, VA	765.00	765.00	ST	3.04		1
6	0702 BIG SANDY, KY	BROADFORD, VA	765.00	765.00	ALUMT	58.26		1
7	0703 HANGING ROCK, OH	JEFFERSON, IN	765.00	765.00	ST	154.74		1
8	0300 BIG SANDY, KY	TRI-STATE, WV	345.00	345.00	ST	8.36		1
9	0600 HAZARD, KY	PINEVILLE, KY	161.00	161.00	WP	45.62		1
10	0600 HAZARD, KY	PINEVILLE, KY	161.00	161.00	ST	0.72		1
11	0135 WOOTEN	ARNOLD DELVINTA (LGE)	161.00	161.00	WP	1.09		1
12	0136 WOOTEN EXTENSION		161.00	161.00	ST			1
13	0100 BIG SANDY, KY	BELLEFONTE	138.00	138.00	ALUM	12.08		1
14	0100 BIG SANDY, KY	BELLEFONTE	138.00	138.00	ST	14.77		1
15	0101 BIG SANDY, KY	W HUNTINGTON, WV	138.00	138.00	ST	0.33		1
16	0102 BELLEFONTE, KY	N PROCTORVILLE, OH	138.00	138.00	ST	1.10	1.10	1
17	0103 HAZARD, KY	BEAVER CREEK, KY	138.00	138.00	ST	5.91		1
18	0103 HAZARD, KY	BEAVER CREEK, KY	138.00	138.00	ST	23.25		1
19	0105 CLINCH RIVER, VA	BEAVER CREEK, KY	138.00	138.00	ST	2.30		1
20	0105 CLINCH RIVER, VA	BEAVER CREEK, KY	138.00	138.00	WP	16.09	16.92	1
21	0107 LOGAN, WV	SPRIGG, KY	138.00	138.00	ST	0.64		2
22	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	ALUMT	32.43		1
23	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	WP	10.05		1
24	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	WP	16.41	0.33	1
25	0111 TRI STATE, WV	BELLEFONTE, KY	138.00	138.00	ST	0.71	14.41	1
26	0111 TRI STATE, WV	BELLEFONTE, KY	138.00	138.00	WP	0.38		1
27	0113 CHADWICK	KY ELECTRIC STEEL	138.00	138.00	WP	7.90		1
28	0115 CHADWICK	COALTON	138.00	138.00	WP	0.98		1
29	0133 CHADWICK		138.00	138.00				
30	0117 MILBROOK PARK, OH	FULLERTON	138.00	138.00	WP	5.08	1.58	1
31	0116 BEAVER CREEK	SPICEWOOD	138.00	138.00	WP	25.83		1
32	0116 BEAVER CREEK	SPICEWOOD	138.00	138.00	ST	0.63		
33	0120 HATFIELD	SPRIGG	138.00	138.00	WP	5.88		1
34	0121 HATFIELD	INEZ	138.00	138.00	WP	14.67		1
35	0122 INEZ	LOVELY	138.00	138.00	WP	6.86		1
36					TOTAL	1,260.24	40.50	52

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1	0126 INEZ	MARTIKI	138.00	138.00	WP	0.33		1
2	0127 BIG SANDY	INEZ	138.00	138.00	ST	23.00		1
3	0106 DORTON	FLEMING	138.00	138.00	WP	6.81		1
4	0106 DORTON	FLEMING	138.00	138.00	ST	0.83		
5	0108 BEAVER CREEK	SPRIGG #1	138.00	138.00	WP	32.60		1
6	0124 BIG SANDY	SOUTH NEAL	138.00	138.00	WP	0.01		1
7	0109 BEAVER CREEK	SPRIGG #3	138.00	138.00				
8	0125 BELLEFONTE	AK STEEL OXYGEN PLANT	138.00	138.00	ST	0.22		2
9	0130 JOHNS CREEK	SPRIGG	138.00	138.00	ST	13.00		
10	0131 BAKER	BIG SANDY EXT.	138.00	138.00	ST	1.00		1
11	0128 INEZ	JOHNS CREEK	138.00	138.00	ST	17.00		
12	0129 BEAVER CREEK	JOHNS CREEK	138.00	138.00	ST	22.00		
13	0132 GRANGSTON LOOP		138.00	138.00				
14	0137 HAYS BRANCH	MORGAN FORK	138.00	138.00	ST	8.30		1
15	0138 SOFT SHELL	BEAVER CREEK	138.00	138.00	ST	1.40		2
16	0138 SOFT SHELL	SPICEWOOD	138.00	138.00	ST	1.40		2
17	0139 MORGAN FORK	BETSY LANE	138.00	138.00	ST	0.10		1
18	0139 MORGAN FORK	BEAVER CREEK	138.00	138.00	ST	0.10		1
19	0140 BONNYMAN	SOFT SHELL	138.00	138.00	ST	0.88		2
20	0140 BONNYMAN	SOFT SHELL	138.00	138.00	SP	19.15		1
21								
22	LINES < 132KV		69.00	69.00		594.23	6.16	
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33	Line cost and expense are	not available by individual						
34	transmission line	Total shown in Column j - p						
35								
36					TOTAL	1,260.24	40.50	52

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
954 MCMA								1
954 MCMA								2
								3
954 MCMA								4
								5
								6
351.5 VAR								7
954 MCMA								8
500 MCMCU								9
								10
795 MCM 26/7								11
795 MCM 26/7								12
556.5 VAR								13
								14
1033.5 VAR								15
397.5 MA								16
397.5 MCMCU								17
								18
636 MCMA								19
								20
397 MCMA								21
397.5 MCMA								22
								23
								24
795 MCMA								25
								26
795 MCMA								27
795 MCMA								28
								29
556.5 MCM								30
795 MCMA								31
1590 KCM								32
1033 MCM								33
10335 VAR								34
10335 VAR								35
	33,646,052	331,587,165	365,233,217	163,790	2,298,888		2,462,678	36

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
10335 VAR								1
795 MCMA								2
795 MCMA								3
795 MCMA								4
397 MCMA								5
10335 VAR								6
								7
795 ACSR								8
1033 MCM								9
1351 KCM								10
2-556.5 MCM								11
1033 MCM								12
								13
795 ACSR								14
1590 ACSR								15
1590 ACSR								16
795 ACSR								17
795 ACSR								18
1590 KCM ACSS								19
1590 KCM ACSS								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
	33,646,052	331,587,165	365,233,217	163,790	2,298,888		2,462,678	33
								34
								35
	33,646,052	331,587,165	365,233,217	163,790	2,298,888		2,462,678	36

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	NO LINES ADDED						
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
									1
									2
									3
									4
									5
									6
									7
									8
									9
									10
									11
									12
									13
									14
									15
									16
									17
									18
									19
									20
									21
									22
									23
									24
									25
									26
									27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
									44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ALLEN (KP) - KY	D	46.00	12.00	
2	ALLEN (KP) - KY	D	46.00		
3	ASHLAND - KY	D	69.00		
4	ASHLAND - KY	D	69.00	12.00	
5	BAKER 345KV - KY	T	345.00	138.00	34.50
6	BAKER 765KV - KY	T	765.00	345.00	34.50
7	BAKER 765KV - KY	T	69.00	12.00	
8	BAKER 765KV - KY	T	765.00		
9	BAKER 765KV - KY	T	138.00	34.50	
10	BAKER 765KV - KY	T	69.00	12.00	
11	BAKER 765KV - KY	T	69.00	4.00	
12	BARRENSHE - KY	D	69.00	12.00	
13	BEAVER CREEK - KY	T	138.00	69.00	46.00
14	BEAVER CREEK - KY	T	138.00	34.50	
15	BEAVER CREEK - KY	T	138.00		
16	BECKHAM - KY	D	138.00		
17	BECKHAM - KY	D	138.00	34.50	
18	BEEFHIDE - KY	D	138.00	34.50	
19	BELFRY - KY	D	46.00	12.00	
20	BELHAVEN - KY	D	138.00	13.09	
21	BELLEFONTE 138KV - KY	T	138.00	13.09	
22	BELLEFONTE 138KV - KY	T	138.00	35.00	
23	BELLEFONTE 138KV - KY	T	138.00	69.00	34.50
24	BELLEFONTE 69KV - KY	T	69.00		
25	BETSY LAYNE - KY	T	46.00		
26	BETSY LAYNE - KY	T	138.00	69.00	46.00
27	BETSY LAYNE - KY	T	138.00	34.00	
28	BETSY LAYNE - KY	T	46.00	12.00	
29	BIG SANDY 138KV - KY	T	138.00	13.09	
30	BIG SANDY 138KV - KY	T	138.00	34.50	
31	BIG SANDY 138KV - KY	T	138.00	69.50	13.20
32	BLUE GRASS - KY	D	69.00	12.00	
33	BONNYMAN - KY	T	138.00	70.50	13.00
34	BONNYMAN - KY	T	69.00	34.50	
35	BULAN - KY	D	69.00	12.00	
36	BURDINE - KY	D	46.00	12.00	
37	BURTON - KY	D	46.00	12.00	
38	BUSSEYVILLE - KY	D	138.00	34.50	
39	CANNONSBURG - KY	D	69.00	34.50	
40	CEDAR CREEK - KY	T	138.00	69.00	46.00

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	CEDAR CREEK - KY	T	69.00	12.00	
2	CEDAR CREEK - KY	T	138.00	34.50	
3	CEDAR CREEK - KY	T	138.00	34.50	
4	CHADWICK - KY	T	138.00	69.00	34.50
5	CHAVIES - KY	D	69.00	12.00	
6	CHAVIES - KY	D	69.00		
7	COALTON - KY	D	69.00		
8	COALTON - KY	D	69.00	12.00	
9	COLEMAN - KY	D	69.00	12.00	
10	COLEMAN - KY	D	69.00	34.50	
11	COLLIER - KY	D	69.00	34.00	
12	COLLIER - KY	D	69.00		
13	COMBS - KY	D	69.00		
14	COMBS - KY	D	69.00	12.00	
15	DAISY - KY	D	69.00	12.00	
16	DAISY - KY	D	69.00		
17	DEWEY - KY	T	69.00		
18	DEWEY - KY	T	138.00	69.00	12.00
19	DEWEY - KY	T	138.00	34.50	
20	DORTON - KY	T	138.00	46.00	
21	DRAFFIN - KY	D	46.00	12.00	
22	EAST PRESTONSBURG - KY	D	46.00	12.00	
23	ELKHORN CITY - KY	T	69.00	46.00	
24	ELKHORN CITY - KY	T	69.00	12.00	
25	ELKHORN CITY - KY	T	69.00		
26	ELWOOD (KP) - KY	D	46.00		
27	ELWOOD (KP) - KY	D	46.00	34.50	6.50
28	ENGLE - KY	D	69.00	34.50	
29	FALCON - KY	D	69.00	12.00	
30	FALCON - KY	D	69.00	46.00	
31	FEDS CREEK - KY	D	69.00	12.00	
32	FISHTRAP - KY	D	69.00	12.00	
33	FLEMING - KY	T	69.00	12.00	
34	FLEMING - KY	T	138.00	69.00	46.00
35	FLEMING - KY	T	69.00		
36	FORDS BRANCH - KY	D	46.00		
37	FORDS BRANCH - KY	D	46.00	34.50	12.00
38	FORDS BRANCH STEPDOWN - KY	D	34.50	12.00	
39	FORTY SEVENTH STREET - KY	D	69.00	13.09	
40	GARRETT (KP) - KY	T	46.00	12.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	GRAHN - KY	D	69.00	12.00	
2	GRAYS BRANCH - KY	D	69.00	12.00	
3	GRAYSON - KY	D	69.00	12.00	
4	HADDIX - KY	D	69.00	34.50	
5	HADDIX - KY	D	69.00		
6	HATFIELD (KP) - KY	T	138.00	69.00	46.00
7	HAYWARD - KY	D	69.00	13.09	
8	HAZARD - KY	T	138.00	69.00	12.00
9	HAZARD - KY	T	161.00	138.00	11.00
10	HAZARD - KY	T	138.00	34.00	
11	HAZARD - KY	T	34.50	12.00	
12	HAZARD - KY	T	138.00		
13	HAZARD - KY	T	69.00		
14	HAZARD - KY	T	69.00	34.00	2.50
15	HENRY CLAY - KY	D	46.00		
16	HENRY CLAY - KY	D	46.00	34.50	
17	HIGHLAND (KP) - KY	D	69.00	13.09	
18	HITCHINS - KY	D	69.00	13.09	
19	HOODS CREEK - KY	D	69.00	12.00	
20	HOWARD COLLINS - KY	D	69.00	12.00	
21	INDEX - KY	D	69.00	12.00	
22	INEZ - KY	T	138.00	69.00	13.09
23	INEZ - KY	T	138.00		
24	INEZ - KY	T	69.00		
25	JACKSON - KY	D	69.00		
26	JACKSON - KY	D	69.00	12.00	
27	JEFF - KY	D	69.00	36.20	
28	JENKINS - KY	D	69.00	12.00	
29	JOHNS CREEK - KY	T	138.00	69.00	34.00
30	JOHNS CREEK - KY	T	138.00		
31	JOHNS CREEK - KY	T	69.00		
32	KENWOOD - KY	D	46.00		
33	KENWOOD - KY	D	46.00	12.00	
34	KEYSER - KY	D	69.00	12.00	
35	KIMPER - KY	D	69.00	12.00	
36	LESLIE - KY	T	161.00	69.00	12.00
37	LESLIE - KY	T	69.00	34.50	
38	LESLIE - KY	T	69.00		
39	LOUISA - KY	D	34.50	12.00	
40	LOVELY - KY	D	138.00	34.00	

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	MANSBACH - KY	D	69.00	4.00	
2	MAYKING - KY	D	69.00	12.00	
3	MAYO TRAIL - KY	D	69.00	12.00	
4	MCKINNEY - KY	D	34.50	12.00	
5	MCKINNEY - KY	D	46.00	34.00	
6	MIDDLE CREEK - KY	D	46.00	12.00	
7	MORGAN FORK - KY	T	138.00		
8	NEW CAMP - KY	D	69.00	12.00	
9	OLIVE HILL - KY	D	69.00	4.00	
10	OLIVE HILL - KY	D	69.00	12.00	
11	PIKEVILLE - KY	D	69.00	12.00	
12	PRESTONSBURG - KY	D	46.00	13.09	
13	PRESTONSBURG - KY	D	46.00		
14	PRINCESS - KY	D	69.00		
15	PRINCESS - KY	D	69.00	34.50	
16	RACELAND - KY	D	69.00	2.40	
17	REEDY COAL - KY	D	69.00	34.00	
18	RUSSELL - KY	D	69.00	12.00	
19	RUSSELL FORK - KY	D	69.00	12.00	
20	SALISBURY (KP) - KY	D	46.00	13.09	
21	SECOND FORK - KY	D	69.00	12.00	
22	SECOND FORK - KY	D	69.00		
23	SHAMROCK - KY	D	69.00	34.50	
24	SIDNEY - KY	D	69.00	12.00	
25	SILOAM - KY	D	69.00	12.00	
26	SLEMP - KY	D	69.00	34.00	
27	SLEMP - KY	D	69.00	34.50	
28	SOFT SHELL - KY	D	138.00	34.50	
29	SOUTH PIKEVILLE - KY	D	69.00	13.09	
30	SOUTH SHORE - KY	D	69.00	13.09	
31	SPRING FORK - KY	D	46.00	7.20	
32	STINNETT - KY	D	161.00	34.00	7.20
33	STINNETT - KY	D	161.00	34.50	7.20
34	STINNETT - KY	D	161.00	34.50	7.20
35	STONE - KY	T	138.00	69.00	46.00
36	TENTH STREET - KY	D	69.00	13.09	
37	THELMA - KY	T	138.00	69.00	12.00
38	THELMA - KY	T	138.00	69.00	46.00
39	THELMA - KY	T	138.00		
40	THELMA - KY	T	46.00		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	TOM WATKINS - KY	D	69.00	12.00	
2	TOPMOST - KY	D	138.00	13.09	
3	VICCO - KY	D	138.00	34.50	
4	WEEKSBURY - KY	D	69.00	12.00	
5	WEST PAINTSVILLE - KY	D	69.00	12.00	
6	WEST PAINTSVILLE - KY	D	69.00	12.00	
7	WHITESBURG - KY	D	69.00		
8	WHITESBURG - KY	D	69.00	12.00	
9	WORTHINGTON - KY	D	69.00	12.00	
10	WURTLAND - KY	D	69.00	12.00	
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Total Capacity (In MVa) (k)	Line No.
6	1					1
			STATCAP	1	13	2
			STATCAP	1	16	3
22	1					4
672	1					5
1500	3					6
3		1				7
			REACTOR	1	100	8
30		1				9
11		1				10
3		1				11
25	1					12
146	2					13
30	1					14
			STATCAP	4	235	15
			STATCAP	1	43	16
30	1					17
20	1					18
11	1					19
20	1					20
22	1					21
45	1					22
308	2					23
			STATCAP	1	14	24
			STATCAP	1	10	25
50	1					26
25	1					27
6	1					28
20	1					29
20	1					30
129	1					31
11	1					32
130	1					33
30	1					34
9	1					35
8	1					36
6	1					37
55	2					38
25	1					39
90	1					40

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
6		1				1
30		1				2
25		1				3
200	1					4
4	1					5
			STATCAP	1	10	6
			STATCAP	1	14	7
25	1					8
4	1					9
20	1					10
25	1					11
			STATCAP	1	10	12
			STATCAP	1	13	13
8	1					14
5	1					15
			STATCAP	1	13	16
			STATCAP	1	27	17
90	1					18
25	1					19
45	1					20
11	1					21
20	1					22
20	1					23
11	1					24
			STATCAP	1	14	25
			STATCAP	1	14	26
25	1					27
20	1					28
20	1					29
20	1					30
22	1					31
4	1					32
20	1					33
130	1					34
			STATCAP	1	14	35
			STATCAP	1	10	36
30	1					37
4	1					38
20	1					39
11	1					40

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
3	1					1
5	1					2
20	1					3
25	1					4
			STATCAP	1	5	5
60	1					6
9	1					7
180	2					8
135	3					9
30	1					10
9	1					11
			STATCAP	1	32	12
			STATCAP	2	68	13
6		1				14
			STATCAP	1	10	15
30	1					16
25	1					17
25	1					18
11	1					19
31	2					20
9	1					21
50	1					22
			STATCAP	2	106	23
			STATCAP	1	10	24
			STATCAP	1	10	25
15	2					26
30	1					27
11	1					28
90	1					29
			STATCAP	1	53	30
			STATCAP	1	10	31
			STATCAP	1	7	32
20	1					33
20	1					34
9	1					35
90	1					36
30	1					37
			STATCAP	1	14	38
10	2					39
30	1					40

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
9	1					1
20	1					2
25	1					3
7	1					4
20	1					5
4	1					6
			STATCAP	1	43	7
20	1					8
5	1					9
8	1					10
25	1					11
10	1					12
			STATCAP	1	10	13
			STATCAP	1	22	14
20	1					15
8	1					16
20	1					17
22	1					18
4	1					19
20	1					20
8	1					21
			STATCAP	1	14	22
11	1					23
20	1					24
5	1					25
20	1					26
11	1					27
30	1					28
25	1					29
8	1					30
1	1					31
15	1					32
22	1					33
22		1				34
50	1					35
50	2					36
90	1					37
70	1					38
			STATCAP	1	32	39
			STATCAP	1	7	40

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
11	1					1
20	1					2
30	1					3
6	1					4
25	1					5
20		1				6
			STATCAP	1	13	7
36	2					8
2	1					9
20	1					10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Administrative and General Expenses - Maintenance	AEPSC	935	967,507
3	Administrative and General Expenses - Operation	AEPSC	Various	4,280,359
4	Assets & Other Debits - Current and Accrued Assets	APCo	163,174	321,736
5	Distribution Expenses - Maintenance	OPCo	Various	547,434
6	Audit Services	AEPSC	920	526,046
7	Central Machine Shop	APCo	Various	1,264,811
8	Construction Services	AEPSC	107,108	20,034,128
9	Corporate Accounting	AEPSC	920	1,340,907
10	Corporate Planning and Budgeting	AEPSC	920	686,642
11	Customer Accounts Expenses	AEPSC	Various	3,262,630
12	Distribution Expenses	AEPSC	Various	1,610,552
13	Barging	I&M	151	4,597,313
14	Real Estate & Workplace Svcs	AEPSC	920,923	263,913
15	Factored Customer A/R Bad Debts	AEP Credit	426.5	2,148,359
16	Factored Customer A/R Expense	AEP Credit	426.5	879,953
17	Fleet and Vehicle Charges	APCo	Various	595,860
18	Fuel & Storeroom Services	AEPSC	152,163	2,954,684
19	Human Resources	AEPSC	920,923	794,229
20	**Non-power Goods or Services Provided for Affiliate**			
21	Assets & Other Debits - Current and Accrued Assets	AGR	152,163,165	448,544
22	Assets and Other Debits - Utility Plant	KYTCo	107	412,055
23	Building and Property Leases	AEPSC	454	270,568
24	Fleet and Vehicle Charges	AEPSC	Various	1,307,743
25	Materials and Supplies	APCo	154	3,518,138
26	O&M Services for Jointly Owned Facility- Mitchell	AGR	Various	14,638,387
27	O&M Services for Jointly Owned Facility- Mitchell	WPCo	Various	119,982,379
28	Power Production Expenses - Steam Power Gen-Maint	AGR	Various	1,641,064
29	Power Production Expenses - Steam Power Gen-Oper	AGR	Various	2,153,834
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2	Information Technology	AEPSC	920,923	1,266,974

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3	Legal GC/Administration	AEPSC	920	1,568,873
4	Materials and Supplies	APCo	Various	2,570,593
5	Materials and Supplies	OPCo	Various	920,452
6	Other Power Supply Expense	AEPSC	555-557	2,080,836
7	Regulatory Services	AEPSC	920	551,288
8	Research and Other Services	AEPSC	Various	960,832
9	Steam Power Generation - Maintenance	AEPSC	510-514	5,286,720
10	Steam Power Generation - Operation	AEPSC	Various	5,118,516
11	Transmission Expenses - Maintenance	AEPSC	Various	1,425,971
12	Transmission Expenses - Operation	AEPSC	Various	3,353,420
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2				
3				
4				

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Schedule Page: 429 Line No.: 2 Column: b

Certain managerial and professional services provided by AEPSC are allocated among multiple affiliates. The costs of the services are billed on a direct-charge basis whenever possible. Costs incurred to perform services that benefit more than one company are allocated to the benefiting companies using one of 80 FERC accepted allocation factors. The allocation factors used to bill for services performed by AEPSC are based upon fomulae that consider factors such as number of customers, number of employees, number of transmission miles, number of invoices and other factors. The data upon which these formulae are based is updated monthly, quarterly, semi-annually or annually, depending on the particular factor and its volatility. The billings for services are made at cost and include no compensation for a return on investment.

Schedule Page: 429 Line No.: 3 Column: c

920-923,925-926,928,930.1,930.2,931

Schedule Page: 429 Line No.: 5 Column: c

592-598

Schedule Page: 429 Line No.: 7 Column: c

107,108,500,506,510,512,513

Schedule Page: 429 Line No.: 11 Column: c

901-903,905

Schedule Page: 429 Line No.: 12 Column: c

580-588,590-598

Schedule Page: 429 Line No.: 17 Column: c

Costs related to AEP's fleet vehicles are allocated in the same manner as the labor of each department utilizing the vehicles. To the extent a department provides service to another affiliate company, an applicable share of their fleet costs are also assigned to that affiliate company.

Schedule Page: 429 Line No.: 24 Column: c

Costs related to AEP's fleet vehicles are allocated in the same manner as the labor of each department utilizing the vehicles. To the extent a department provides service to another affiliate company, an applicable share of their fleet costs are also assigned to that affiliate company.

Schedule Page: 429 Line No.: 26 Column: c

107,108,151,154,186,408,421,426,431,500-506,510-514,920-926,928,930,931,935

Schedule Page: 429 Line No.: 27 Column: c

107,108,151,154,186,408,421,426,431,500-506,510-514,920-926,928,930,931,935

Schedule Page: 429 Line No.: 28 Column: c

510-514

Schedule Page: 429 Line No.: 29 Column: c

500,501,502,506

Schedule Page: 429.1 Line No.: 4 Column: c

107,108,154,163,184,512-514,562,566,570,585-588,592-596,598,903,930,935

Schedule Page: 429.1 Line No.: 5 Column: c

107,154,163,512,513,560,566,571,585,586,588,593-595,598,930,935

Schedule Page: 429.1 Line No.: 8 Column: c

183,186,188

Schedule Page: 429.1 Line No.: 10 Column: c

500-502,505,506,508

Schedule Page: 429.1 Line No.: 11 Column: c

568,569-569.3,570,571-573

Schedule Page: 429.1 Line No.: 12 Column: c

560,561.1,561.2,561.5,561.6,562-564,566

INDEX

Schedule	Page No.

Schedule	Page No.