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

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2014)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2014)
Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

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 2012/Q4

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 Eamings	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 Govemments 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 2012/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)* 04/11/2013

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 Andrew B. Reis	03 Signature Andrew B. Reis	04 Date Signed *(Mo, Da, Yr)* 04/11/2013
02 Title Assistant Controller		

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	04/11/2013	End of 2012/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	N/A
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	
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	N/A
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	
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	N/A
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	
25	Unrecovered Plant and Regulatory Study Costs	230	
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	
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	04/11/2013	End of 2012/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)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	N/A
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	N/A
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	
57	Amounts Included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	
65	Pumped Storage Generating Plant Statistics	408-409	
66	Generating Plant Statistics Pages	410-411	

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	04/11/2013	End of 2012/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: [ ] 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	04/11/2013	End of 2012/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.

Andrew B. Reis, 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	04/11/2013	End of 2012/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	04/11/2013	End of 2012/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)
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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	04/11/2013	End of 2012/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		
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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	04/11/2013	2012/Q4

FOOTNOTE DATA

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 ($)(2) (d)	Option Awards ($) (e)	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 — President and Chief Executive Officer	903,461	—	4,600,008	—	1,500,000	176,312	106,709	7,286,490
Brian X. Tierney — Executive Vice President and Chief Financial Officer	652,500	—	1,896,860	—	800,000	228,760	49,467	3,627,587
Robert P. Powers — Executive Vice President and Chief Operating Officer	652,500	—	1,896,860	—	800,000	586,359	60,809	3,996,528
Dennis E. Welch(6) — Executive Vice President and Chief External Officer	465,283	—	920,291	—	415,000	81,405	39,275	1,921,254
David M. Feinberg(7) — Executive Vice President and General Counsel	451,731	—	857,807	—	450,000	30,361	37,044	1,826,943

(1) Amounts in the salary column are composed of executive salaries paid for the year shown, which include 261 days of pay for 2012, which 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 total grant date fair value, calculated in accordance with FASB ASC Topic 718, of performance units and restricted stock units granted under our Long-Term Incentive Plan. See Note 14 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2012 for a discussion of the relevant assumptions used in calculating these amounts. The restricted stock units vest over a forty month period. 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. Therefore, the maximum amount payable for the performance units is equal to $5,520,010 for Mr. Akins, $2,276,232 for Mr. Tierney, $2,276,232 for Mr. Powers, $1,104,350 for Mr. Welch and $1,029,368 for Mr. Feinberg.

(3) The amounts shown in this column are annual incentive awards made 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. No named executive officer received preferential or above-market earnings on deferred compensation. See Note 7 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2012, for a discussion of the relevant assumptions.

(5) Amounts shown in the All Other Compensation column for 2012 include: (a) Company contributions to the Company's Retirement Savings Plan, (b) Company contributions to the Company's Supplemental Retirement Savings Plan, (c) perquisites and (d) for Mr. Akins, a tax gross-up associated with a reimbursement for a Company-caused tax penalty. The amounts are listed in the following table:

Name of Respondent Kentucky Power Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2013	Year/Period of Report 2012/Q4

FOOTNOTE DATA

All Other Compensation

Type	Nicholas K. Akins	Brian X. Tierney	Robert P. Powers	Dennis E. Welch	David M. Feinberg
Retirement Savings Plan Match	11,250	11,250	11,250	11,250	11,250
Supplemental Retirement Savings Plan Match	63,000	38,217	38,250	16,846	16,356
Perquisites	28,385	-	11,309	11,179	9,438
Tax Gross-Up	4,074	-	-	-	-
Total	106,709	49,467	60,809	39,275	37,044

Perquisites provided in 2012 included: financial counseling and tax preparation, air and hotel club memberships, and, for Mr. Akins, director's accidental death insurance premium and on one occasion, personal use of Company aircraft for a death in the family. None of the individual perquisites had a value exceeding $25,000 for a named executive officer.

(6) Mr. Welch was not considered an executive officer prior to 2012.

(7) Mr. Feinberg was not considered an executive officer prior to 2012.

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	04/11/2013	End of 2012/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	Barbara D. Radous, Vice President	Columbus, Ohio
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17	David M. Feinberg, Secretary	Columbus, Ohio
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19	Note: The Respondent does not have an Executive Committee	
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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	04/11/2013	End of 2012/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 L.L.C. Attachment H-14	ER08-1329
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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	04/11/2013	End of 2012/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	20120525-5106	05/25/2012	ER08-1329	AEP PJM OATT Formula Update	PJM OATT Attachment
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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	04/11/2013	End of 2012/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)	2
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
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Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report 04/11/2013	Year/Period of Report End of 2012/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.

Name of Respondent Kentucky Power Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2013	Year/Period of Report 2012/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

Item 1 None

Item 2 None

Item 3 None

Item 4 None

Item 5 None

Item 6 None

Item 7 None

Item 8 None

Item 9 None

Item 10 None

Item 11 (Reserved)

Item 12 Not Used

Item 13 Nicholas K. Akins appointed as Chairman of the Board effective January 1, 2012
David M. Feinberg appointed as Director and Secretary effective January 1, 2012
Mark C. McCullough appointed as Director effective January 1, 2012
Scott N. Smith appointed as Vice President effective January 26, 2012
Anne M. Vogel resigned as Assistant Secretary effective March 13, 2012
Mark C. McCullough appointed as Vice President effective May 22, 2012
Barbara D. Radous resigned as Director and Vice President effective December 31, 2012
Charles E. Zebula resigned as Treasurer effective December 31, 2012

Item 14 Proprietary capital ratio exceeds 30%

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	04/11/2013	End of 2012/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	1,757,048,559	1,676,402,340
3	Construction Work in Progress (107)	200-201	44,281,292	71,290,316
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		1,801,329,851	1,747,692,656
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	622,134,082	598,904,121
6	Net Utility Plant (Enter Total of line 4 less 5)		1,179,195,769	1,148,788,535
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)		1,179,195,769	1,148,788,535
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		964,528	964,528
19	(Less) Accum. Prov. for Depr. and Amort. (122)		208,286	201,616
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	2,361,232	3,525,928
24	Other Investments (124)		5,003,210	5,013,390
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)		0	0
30	Long-Term Portion of Derivative Assets (175)		6,840,814	8,294,333
31	Long-Term Portion of Derivative Assets – Hedges (176)		40,841	5,525
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		15,002,339	17,602,088
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		1,481,978	778,210
36	Special Deposits (132-134)		1,920,501	3,409,369
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	534
40	Customer Accounts Receivable (142)		12,676,053	12,937,725
41	Other Accounts Receivable (143)		150,660	74,473
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		141,538	622,726
43	Notes Receivable from Associated Companies (145)		0	70,331,843
44	Accounts Receivable from Assoc. Companies (146)		9,241,088	8,405,383
45	Fuel Stock (151)	227	67,280,320	22,597,653
46	Fuel Stock Expenses Undistributed (152)	227	1,866,856	408,137
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	12,908,316	13,124,755
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	14,514,196	17,553,006

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	04/11/2013	End of 2012/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		2,361,232	3,525,928
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)		1,569,795	1,459,828
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		1,285	1,850,772
60	Rents Receivable (172)		2,989,753	2,507,697
61	Accrued Utility Revenues (173)		816,939	3,379,418
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		12,993,718	16,596,991
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		6,840,814	8,294,333
65	Derivative Instrument Assets - Hedges (176)		62,756	91,247
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		40,841	5,525
67	Total Current and Accrued Assets (Lines 34 through 66)		131,089,789	163,058,529
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		2,205,280	2,509,741
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	214,230,662	215,517,254
73	Prelim. Survey and Investigation Charges (Electric) (183)		33,084,274	3,980,393
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	15,013,747	16,049,416
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)		670,167	703,816
82	Accumulated Deferred Income Taxes (190)	234	28,379,702	34,382,679
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		293,583,832	273,143,299
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		1,618,871,729	1,602,592,451

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	04/11/2013	end of 2012/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	238,750,000	238,750,000
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	190,818,915	171,840,462
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)	-408,880	-625,244
16	Total Proprietary Capital (lines 2 through 15)		479,610,035	460,415,218
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	20,000,000	20,000,000
21	Other Long-Term Debt (224)	256-257	530,000,000	530,000,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		778,050	944,775
24	Total Long-Term Debt (lines 18 through 23)		549,221,950	549,055,225
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		1,674,301	2,387,568
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		36,781	108,514
29	Accumulated Provision for Pensions and Benefits (228.3)		30,094,754	46,427,476
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		1,635,430	0
32	Long-Term Portion of Derivative Instrument Liabilities		3,617,651	2,673,829
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		82,731	60,485
34	Asset Retirement Obligations (230)		3,902,259	3,771,555
35	Total Other Noncurrent Liabilities (lines 26 through 34)		41,043,907	55,429,427
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		30,336,777	36,075,935
39	Notes Payable to Associated Companies (233)		13,358,855	0
40	Accounts Payable to Associated Companies (234)		41,052,680	35,218,553
41	Customer Deposits (235)		23,484,965	22,074,077
42	Taxes Accrued (236)	262-263	6,548,715	19,319,996
43	Interest Accrued (237)		7,166,695	7,713,477
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	04/11/2013	end of 2012/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)		2,061,227	2,642,201
48	Miscellaneous Current and Accrued Liabilities (242)		15,736,581	16,810,756
49	Obligations Under Capital Leases-Current (243)		1,403,876	1,452,627
50	Derivative Instrument Liabilities (244)		6,749,162	7,842,458
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		3,617,651	2,673,829
52	Derivative Instrument Liabilities - Hedges (245)		271,288	520,854
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		82,731	60,485
54	Total Current and Accrued Liabilities (lines 37 through 53)		144,470,439	146,936,620
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		63,178	92,999
57	Accumulated Deferred Investment Tax Credits (255)	266-267	355,759	633,764
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	5,121,329	6,347,451
60	Other Regulatory Liabilities (254)	278	13,831,966	8,302,739
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	26,644,638	28,229,670
63	Accum. Deferred Income Taxes-Other Property (282)		252,501,733	243,161,376
64	Accum. Deferred Income Taxes-Other (283)		106,006,795	103,987,962
65	Total Deferred Credits (lines 56 through 64)		404,525,398	390,755,961
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		1,618,871,729	1,602,592,451

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	04/11/2013	End of 2012/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	631,455,274	741,001,224		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	408,136,355	521,178,155		
5	Maintenance Expenses (402)	320-323	46,464,797	51,354,293		
6	Depreciation Expense (403)	336-337	51,083,564	49,832,280		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	3,382,893	3,573,500		
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)		289,087	311,515		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	12,159,972	11,643,088		
15	Income Taxes - Federal (409.1)	262-263	11,025,629	4,178,555		
16	- Other (409.1)	262-263	2,315,915	3,189,038		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	61,561,067	65,047,272		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	51,377,005	47,081,447		
19	Investment Tax Credit Adj. - Net (411.4)	266	-278,005	-359,377		
20	(Less) Gains from Disp. of Utility Plant (411.6)		3,110	2,735		
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		15,363	1,503		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		544,784,412	662,901,250		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		86,670,862	78,099,974		

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	04/11/2013	End of 2012/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
631,455,274	741,001,224					2
						3
408,136,355	521,178,155					4
46,464,797	51,354,293					5
51,083,564	49,832,280					6
						7
3,382,893	3,573,500					8
38,616	38,616					9
						10
						11
289,087	311,515					12
						13
12,159,972	11,643,088					14
11,025,629	4,178,555					15
2,315,915	3,189,038					16
61,561,067	65,047,272					17
51,377,005	47,081,447					18
-278,005	-359,377					19
3,110	2,735					20
						21
15,363	1,503					22
						23
						24
544,784,412	662,901,250					25
86,670,862	78,099,974					26

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2013	Year/Period of Report End of 2012/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)		86,670,862	78,099,974		
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)		48,800	49,330		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		257,457	2,192,117		
38	Allowance for Other Funds Used During Construction (419.1)		1,574,384	1,229,389		
39	Miscellaneous Nonoperating Income (421)		565,147	319,631		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		2,445,788	3,790,467		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		322,570	434,850		
46	Life Insurance (426.2)					
47	Penalties (426.3)		18	3,255		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		304,052	328,859		
49	Other Deductions (426.5)		2,523,348	2,511,770		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		3,149,988	3,278,734		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	56,600	56,600		
53	Income Taxes-Federal (409.2)	262-263	-757,316	-142,028		
54	Income Taxes-Other (409.2)	262-263	15,788	111,120		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	8,797	62,449		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	113,320	261,856		
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)		-789,451	-173,715		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		85,251	685,448		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		33,998,706	33,998,706		
63	Amort. of Debt Disc. and Expense (428)		471,186	471,186		
64	Amortization of Loss on Reaquired Debt (428.1)		33,649	33,649		
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)		1,051,134	1,050,312		
68	Other Interest Expense (431)		1,347,524	1,757,911		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		1,124,539	900,290		
70	Net Interest Charges (Total of lines 62 thru 69)		35,777,660	36,411,474		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		50,978,453	42,373,948		
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)		50,978,453	42,373,948		

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	04/11/2013	End of 2012/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		171,840,462	157,466,514
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)		50,978,453	42,373,948
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		-32,000,000	(28,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-32,000,000	(28,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		190,818,915	171,840,462
	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	04/11/2013	End of 2012/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)		190,818,915	171,840,462
	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	04/11/2013	End of 2012/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)	50,978,453	42,373,948
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	54,505,073	53,444,396
5	Amortization of Regulatory Debits and Credits (Net)	289,087	311,515
6			
7	Mark-to-Market of Risk Management Contracts	2,509,976	-219,954
8	Deferred Income Taxes (Net)	10,079,539	17,766,418
9	Investment Tax Credit Adjustment (Net)	-278,005	-359,377
10	Net (Increase) Decrease in Receivables	225,347	13,568,315
11	Net (Increase) Decrease in Inventory	-45,924,947	-7,325,089
12	Net (Increase) Decrease in Allowances Inventory	3,038,810	-108,421
13	Net Increase (Decrease) in Payables and Accrued Expenses	-14,366,705	-15,159,738
14	Net (Increase) Decrease in Other Regulatory Assets	-8,849,896	3,709,500
15	Net Increase (Decrease) in Other Regulatory Liabilities	933,562	-2,219,445
16	(Less) Allowance for Other Funds Used During Construction	1,574,384	1,229,389
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):	-2,657,705	-208,055
19	Customer Deposits	1,410,888	2,381,550
20	Over/Under Recovered Fuel (Net)	4,790,377	2,274,017
21	Pension Contributions	-4,902,000	-10,535,000
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	50,207,470	98,465,191
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-103,229,573	-67,127,402
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	-1,574,384	-1,229,389
31	Other (provide details in footnote):		
32			
33	Acquired Assets	-418,682	-1,288,581
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-102,073,871	-67,186,594
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	656,838	438,849
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	04/11/2013	End of 2012/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	4	73
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54			
55	Notes Receivable from Associated Companies	70,331,843	-3,272,100
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-31,085,186	-70,019,772
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):	222,629	51,819
68	Notes Payable to Associated Companies	13,358,855	
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	13,581,484	51,819
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-32,000,000	-28,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-18,418,516	-27,948,181
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	703,768	497,238
87			
88	Cash and Cash Equivalents at Beginning of Period	778,210	280,972
89			
90	Cash and Cash Equivalents at End of period	1,481,978	778,210

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	04/11/2013	2012/Q4

FOOTNOTE DATA

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

	2012 Cash Flow Incr / (Decr)	2011 Cash Flow Incr / (Decr)
Utility Plant, Net	$ (9,570,580)	$ (4,174,429)
Property and Investments, Net	16,846	21,887
Margin Deposits	1,488,868	1,947,884
Prepayments	3,134,974	2,831,715
Accrued Utility Revenues, Net	2,562,479	443,974
Miscellaneous Current and Accrued Assets	-	8
Unamortized Debt Expense	304,461	304,461
Other Deferred Debits, Net	935,732	(6,895,114)
Other Comprehensive Income, Net	(4,711)	186,074
Unamortized Discount/Premium on Long-Term Debt	166,725	166,725
Accumulated Provisions - Misc	1,248,722	(180,263)
Current and Accrued Liabilities, Net	(1,136,325)	1,209,339
Other Deferred Credits, Net	(1,804,896)	3,929,684
Total	**$ (2,657,705)**	**$ (208,055)**

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

	2012 Cash Flow Incr / (Decr)	2011 Cash Flow Incr / (Decr)
Sales of transformers to various associated companies	$ 211,014	$ 149,625
Sales of meters to various associated companies	149,005	254,895
Sale of Electrohydraulic Control System to associated company	296,819	-
Proceeds from acquired assets subject to operating lease	-	34,329
Total	**$ 656,838**	**$ 438,849**

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report 04/11/2013	Year/Period of Report End of 2012/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 Commission 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.

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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 or Parent	American Electric Power Company, Inc., an electricity utility holding company.
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.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP West Companies	PSO, SWEPCo, TCC and TNC.
AFUDC	Allowance for Funds Used During Construction.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
CAA	Clean Air Act.
CO_2	Carbon dioxide and other greenhouse gases.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation. AEPSC acts as the agent.
CWIP	Construction Work in Progress.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company.
FAC	Fuel Adjustment Clause.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
MISO	Midwest Independent Transmission System Operator.
MMBtu	Million British Thermal Units.

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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.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
NO_x	Nitrogen oxide.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana, owned by AEGCo and I&M.
RTO	Regional Transmission Organization.
SIA	System Integration Agreement, effective June 15, 2000, 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.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North 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.

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NOTES TO FINANCIAL STATEMENTS (Continued)

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

As a public utility, KPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 173,000 retail customers in its service territory in eastern Kentucky. KPCo also sells power at wholesale to municipalities.

The Interconnection Agreement permits the AEP East Companies to pool their generation assets on a cost basis. It establishes an allocation method for generating capacity among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. Members of the Interconnection Agreement are compensated for their costs of energy delivered and charged for energy received. The capacity reserve relationship of the Interconnection Agreement members changes as generating assets are added, retired or sold and relative peak demand changes. The Interconnection Agreement calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the MLR, which determines each member's percentage share of revenues and costs. The addition of APCo's Dresden Plant in January 2012 and removal of OPCo's Sporn Plant, Unit 5 in September 2011 changed the capacity reserve relationship of the members.

The AEP East Companies are parties to a Transmission Agreement defining how they share the revenues and costs associated with their relative ownership of transmission assets. This sharing was based upon each company's MLR until the FERC approved a new Transmission Agreement effective November 2010. The new Transmission Agreement will be phased in for retail rates, added KGPCo and WPCo as parties to the agreement and changed the allocation method.

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

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East Companies and trading and marketing activities originating in SPP generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among the AEP East Companies, PSO and SWEPCo in proportion to the marketing realization directly assigned to each zone for the current month plus the preceding eleven months.

AEPSC conducts power, gas, coal and emission allowance risk management activities on KPCo's behalf. KPCo shares in the revenues and expenses associated with these risk management activities, as described in the preceding paragraph, with the other AEP East Companies, PSO and SWEPCo. Power and gas risk management activities are allocated based on the Interconnection Agreement and the SIA. KPCo shares in coal and emission allowance risk management activities based on its proportion of fossil fuels burned by the AEP System. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and, to a lesser extent, gas, coal and emission allowances. The electricity, gas, coal and emission allowance contracts include physical transactions, over-the-counter options and financially-settled swaps and exchange-traded futures and options. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts.

To minimize the credit requirements and operating constraints when operating within PJM, the AEP East Companies, as well as KGPCo and WPCo, agreed to a netting of all payment obligations incurred by any of the AEP East Companies against all balances due to the AEP East Companies and to hold PJM harmless from actions that any one or more AEP East Companies may take with respect to PJM.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

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

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

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

In addition, the FERC regulates the SIA, the Interconnection Agreement, the System Transmission Integration Agreement, the Transmission Agreement and the AEP System Interim Allowance Agreement, all of which allocate shared system costs and revenues to the utility subsidiaries that are parties to each agreement. In October 2012, the AEP East Companies asked the FERC to terminate the existing Interconnection Agreement and the AEP System Interim Allowance Agreement and approve a new Power Coordination Agreement among APCo, I&M and KPCo. A decision is expected from the FERC in mid-2013.

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NOTES TO FINANCIAL STATEMENTS (Continued)

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 classification of accrued non-ARO asset removal costs as accumulated depreciation rather than regulatory liabilities.
- 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 an accrued provision for potential refund as other noncurrent liability rather than a current 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 certain other assets and liabilities as current instead of noncurrent.
- The classification of certain other assets and liabilities as noncurrent instead of current.

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

	2012	2011
	(in thousands)	
For the Years Ended December 31,		
Cash Was Paid (Received) for:		
Interest (Net of Capitalized Amounts)	$ 35,516	$ 36,098
Income Taxes (Net of Refunds)	23,089	7,785
Noncash Acquisitions Under Capital Leases	741	264
At December 31,		
Construction Expenditures Included in Current and Accrued Liabilities	9,752	7,446

Special Deposits

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

Inventory

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

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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 11 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, 2012.

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

Emission Allowances

KPCo records emission allowances at cost, including the annual SO_2 and NO_x emission allowance entitlements received at no cost from the Federal EPA. KPCo follows the inventory model for these allowances. These allowances are consumed in the production of energy and are recorded in Operation Expenses at an average cost. The purchases and sales of allowances are reported in the Operating Activities section of the statements of cash flows. The net margin on sales of emission allowances is included in Operating Revenues. The net margin on sales of emission allowances affects the determination of deferred fuel or deferred emission allowance costs and the amortization of regulatory assets.

Property, Plant and Equipment

Electric utility property, plant and equipment are stated at original 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 the original cost, 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 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 the plants are included in operating expenses.

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

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

Allowance for Funds Used During Construction (AFUDC)

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

Valuation of Nonderivative Financial Instruments

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

Fair Value Measurements of Assets and Liabilities

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability. The AEP System's market risk oversight staff independently monitors its valuation policies and procedures and provides members of the Commercial Operations Risk Committee (CORC) various daily, weekly and monthly reports, regarding compliance with policies and procedures. The CORC consists of AEPSC's Chief Operating Officer, Chief Financial Officer, Executive Vice President of Energy Supply, 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 and if the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. 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 significant portion of the Level 3 instruments have been economically hedged which greatly 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.

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Assets in the benefits trusts are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equity securities. They are valued based on observable inputs primarily unadjusted quoted prices in active markets for identical assets. Items classified as Level 2 are primarily investments in individual fixed income securities and cash equivalents funds. Fixed income securities do not trade on an exchange and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments. Benefit plan assets included in Level 3 are primarily real estate and private equity investments that are valued using methods requiring judgment including appraisals.

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Operation Expenses when the fuel is burned or the allowance or consumable is utilized. Fuel cost over-recoveries (the excess of fuel revenues billed to customers over applicable fuel costs incurred) are generally deferred as regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel revenues billed to customers) are generally deferred as regulatory assets. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when there is a phase-in plan or the FAC has been suspended. These deferrals are amortized when refunded or when billed to customers in later months with the KPSC's review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the KPSC. On a routine basis, the KPSC reviews and/or audits KPCo's fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. When a fuel cost disallowance becomes probable, KPCo adjusts its FAC deferrals and records a provision for estimated refunds to recognize these probable outcomes. Changes in fuel costs, including purchased power are reflected in rates in a timely manner through the FAC. A portion of profits from off-system sales are given to customers through the FAC.

Revenue Recognition

Regulatory Accounting

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

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

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Electricity Supply and Delivery Activities

KPCo recognizes revenues from retail and wholesale electricity sales and electricity transmission and distribution delivery services. KPCo recognizes the revenues on the statements of income upon delivery of the energy to the customer and includes unbilled as well as billed amounts.

Most of the power produced at the generation plants of the AEP East Companies is sold to PJM, the RTO operating in the east service territory. The AEP East Companies purchase power from PJM to supply power to their customers. Generally, these power sales and purchases are reported on a net basis in revenues on the statements of income. However, purchases of power in excess of sales to PJM, on an hourly net basis, used to serve retail load are recorded gross as Operation Expenses on the statements of income. Other RTOs in which KPCo participates do not function in the same manner as PJM. They function as balancing organizations and not as exchanges.

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

AEPSC, on behalf of the AEP East Companies, engages in wholesale electricity, coal, natural gas and emission allowances marketing and risk management activities focused on wholesale markets where the AEP System owns assets and adjacent markets. These activities include the purchase and sale of energy under forward contracts at fixed and variable prices. 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 wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. KPCo uses MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or a normal purchase or sale. The realized gains and losses on wholesale marketing and risk management transactions are included in Operating Revenues on the statements of income on a net basis. The unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Certain qualifying wholesale marketing and risk management derivative transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). KPCo initially records the effective portion of the cash flow hedge's gain or loss as a component of AOCI. When the forecasted transaction is realized and affects net income, KPCo subsequently reclassifies the gain or loss on the hedge from AOCI into revenues or expenses within the same financial statement line item as the forecasted transaction on the statements of income. KPCo defers the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains). See "Accounting for Cash Flow Hedging Strategies" section of Note 7.

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. The net amortization expense is included in Amortization of Debt Discount and Expense.

Investments Held in Trust for Future Liabilities

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

Benefit Plans

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

The investment philosophies for AEP's benefit plans support the allocation of assets to minimize risks and 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.

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

Pension Plan Assets	Target
Equity	40.0 %
Fixed Income	50.0 %
Other Investments	10.0 %

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

The investment policy for each benefit plan contains various investment limitations. The investment policies establish concentration limits for securities. Investment policies prohibit the benefit trust funds from purchasing securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, the investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law. Each investment manager's portfolio is compared to a diversified benchmark index.

For equity investments, the limits are as follows:

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

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

- 3% in 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, the following limitations apply:

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

A portion of the pension assets is invested in real estate funds to provide diversification, add return and hedge against inflation. Real estate properties are illiquid, difficult to value and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type and risk classification. Real estate holdings include core, value-added and development risk classifications and some investments in Real Estate Investment Trusts (REITs), which are publicly traded real estate securities classified as Level 1.

A portion of the pension assets is invested in private equity. Private equity investments add return and provide diversification and typically require a long-term time horizon to evaluate investment performance. Private equity is classified as an alternative investment because it is illiquid, difficult to value and not actively traded. The pension plan uses limited partnerships and commingled funds to invest across the private equity investment spectrum. The private equity holdings are with 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 cash collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the cash collateral is invested. The difference between the rebate owed to the borrower and the cash collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is providing modest incremental income with a limited increase in risk.

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

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

Comprehensive Income (Loss)

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

Subsequent Events

Management reviewed subsequent events through April 11, 2013, the date that the 2012 FERC Form 1 was issued.

2. 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

In October 2012, the AEP East Companies submitted several filings with the FERC. See the "Corporate Separation and Termination of Interconnection Agreement" section of FERC Rate Matters. In December 2012, KPCo filed a request with the KPSC for approval to transfer at net book value to KPCo a one-half interest in the Mitchell Plant, comprising 780 MW of average annual generating capacity presently owned by OPCo. If the transfer is approved, KPCo anticipates seeking cost recovery when filing its next base rate case. In addition, KPCo announced its plan to retire Big Sandy Plant, Unit 2 in early 2015, subject to regulatory approval, and its intention to study the conversion of Big Sandy Plant, Unit 1 to burn natural gas instead of coal.

Big Sandy Plant, Unit 2 FGD System

In May 2012, KPCo withdrew its application to the KPSC seeking approval of a Certificate of Public Convenience and Necessity to retrofit Big Sandy Plant, Unit 2 with a dry FGD system. As part of the Mitchell Plant transfer filing discussed above, KPCo requested costs related to the FGD project be established as a regulatory asset and recovered in KPCo's next base rate case. As of December 31, 2012, KPCo has incurred $29 million related to the FGD project, which is recorded in Deferred Charges and Other Noncurrent Assets on the balance sheet. If KPCo is not ultimately permitted to recover its incurred costs, it would reduce future net income and cash flows.

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Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund

In 2004, AEP eliminated transaction-based through-and-out transmission service charges and collected, at the FERC's direction, load-based charges, referred to as RTO SECA through March 2006. Intervenors objected and the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East Companies recognized gross SECA revenues of $220 million. KPCo's portion of recognized gross SECA revenues was $17 million. In 2006, a FERC Administrative Law Judge issued an initial decision finding that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made.

AEP filed briefs jointly with other affected companies asking the FERC to reverse the decision. In May 2010, the FERC issued an order that generally supported AEP's position and required a compliance filing. In August 2010, the affected companies, including the AEP East Companies, filed a compliance filing with the FERC. The AEP East Companies provided reserves for net refunds for SECA settlements. The AEP East Companies settled with various parties prior to the FERC compliance filing and entered into additional settlements subsequent to the compliance filing being filed at the FERC. Based on the analysis of the May 2010 order, the compliance filing and recent settlements, management believes that the reserve is adequate to pay the refunds, including interest, and any remaining exposure beyond the reserve is immaterial.

Corporate Separation and Termination of Interconnection Agreement

In October 2012, the AEP East Companies submitted several filings with the FERC seeking approval to fully separate OPCo's generation assets from its distribution and transmission operations. The AEP East Companies also requested FERC approval to transfer at net book value OPCo's Mitchell Plant to APCo and KPCo in equal one-half interests (780 MW each). Additionally, the AEP East Companies asked the FERC to terminate the existing Interconnection Agreement and approve a new Power Coordination Agreement among APCo, I&M and KPCo. Intervenors have opposed several of these filings. The AEP East Companies have responded and continue to pursue approvals from the FERC. A decision from the FERC is expected in mid-2013. Similar filings have been made at the KPSC. See the "Plant Transfer" section above.

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

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3. EFFECTS OF REGULATION

Regulatory assets and liabilities are comprised of the following items:

Regulatory Assets:	December 31, 2012 (in thousands)	December 31, 2011 (in thousands)	Remaining Recovery Period
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:			
Regulatory Assets Currently Not Earning a Return			
Storm Related Costs	$ 12,146	$ -	
Mountaineer Carbon Capture and Storage Commercial Scale Facility	873	905	
Total Regulatory Assets Not Yet Being Recovered	13,019	905	
Regulatory assets being recovered:			
Regulatory Assets Currently Earning a Return			
RTO Formation/Integration Costs	998	1,194	various
Regulatory Assets Currently Not Earning a Return			
Income Tax Assets	128,656	124,184	23 years
Pension and OPEB Funded Status	52,048	66,392	12 years
Storm Related Costs	11,746	16,445	3 years
Postemployment Benefits	5,230	5,205	5 years
Other Regulatory Assets Being Recovered	2,534	1,192	various
Total Regulatory Assets Being Recovered	201,212	214,612	
Total FERC Account 182.3 Regulatory Assets	$ 214,231	$ 215,517	

Regulatory Liabilities:	December 31, 2012 (in thousands)	December 31, 2011 (in thousands)	Remaining Refund Period
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Not Paying a Return			
Unrealized Gain on Forward Commitments	$ 4,288	$ 3,536	5 years
Income Tax Liabilities	1,167	1,362	23 years
Over-recovered Fuel Costs	7,928	3,138	1 year
Other Regulatory Liabilities Being Paid	449	267	various
Total Regulatory Liabilities Being Paid	13,832	8,303	
Total FERC Account 254 Regulatory Liabilities	$ 13,832	$ 8,303	

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4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

COMMITMENTS

Construction and Commitments

KPCo has substantial construction commitments to support its operations and environmental investments. In managing the overall construction program and in the normal course of business, KPCo contractually commits to third-party construction vendors for certain material purchases and other construction services. Management forecasts approximately $73 million of construction expenditures, excluding equity AFUDC, for 2013. KPCo also purchases fuel, materials, supplies, services and property, plant and equipment under contract as part of its normal course of business. Certain supply contracts contain penalty provisions for early termination.

The following table summarizes KPCo's actual contractual commitments as of December 31, 2012:

Contractual Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(In thousands)		
Fuel Purchase Contracts (a)	$ 115,983	$ 40,662	$ 1,181	$ -	$ 157,826
Energy and Capacity Purchase Contracts (b)	34,074	68,117	67,886	169,487	339,564
Construction Contracts for Capital Assets (c)	3,633	-	-	-	3,633
Total	$ 153,690	$ 108,779	$ 69,067	$ 169,487	$ 501,023

(a) Represents contractual commitments to purchase coal and other consumables as fuel for electric generation along with related transportation of the fuel.
(b) Represents contractual commitments for energy and capacity purchase contracts.
(c) Represents only capital assets for which there are signed contracts. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs.

GUARANTEES

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

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of December 31, 2012, there were no material liabilities recorded for any indemnifications.

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

Lease Obligations

KPCo leases certain equipment under master lease agreements. See "Master Lease Agreements" section of Note 10 for disclosure of lease residual value guarantees.

CONTINGENCIES

Insurance and Potential Losses

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

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

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Carbon Dioxide Public Nuisance Claims

In October 2009, the Fifth Circuit Court of Appeals reversed a decision by the Federal District Court for the District of Mississippi dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that CO_2 emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs' complaint to a coordinate branch of government and that no initial policy determination was required to adjudicate these claims. The court granted petitions for rehearing. An additional recusal left the Fifth Circuit without a quorum to reconsider the decision and the appeal was dismissed, leaving the district court's decision in place. Plaintiffs filed a petition with the U.S. Supreme Court asking the court to remand the case to the Fifth Circuit and reinstate the panel decision. The petition was denied in January 2011. Plaintiffs refiled their complaint in federal district court. The court ordered all defendants to respond to the refiled complaints in October 2011. In March 2012, the court granted the defendants' motion for dismissal on several grounds, including the doctrine of collateral estoppel and the applicable statute of limitations. Plaintiffs appealed the decision to the Fifth Circuit Court of Appeals. Management will continue to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Alaskan Villages' Claims

In 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil and gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. The plaintiffs appealed the decision. In September 2012, the Ninth Circuit Court of Appeals affirmed the trial court's decision, holding that the CAA displaced Kivalina's claims for damages. Plaintiffs' petition for rehearing by the full court was denied in November 2012, but the plaintiffs could seek further review in the U.S. Supreme Court. Management believes the action is without merit and will continue to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

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

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

Superfund addresses clean-up of hazardous substances that have been released to the environment. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. As of December 31, 2012, 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.

5. BENEFIT PLANS

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

KPCo participates in an AEP sponsored qualified pension plan 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 a regulatory asset and deferred gains result in a regulatory liability.

Actuarial Assumptions for Benefit Obligations

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

	Pension Plans		Other Postretirement Benefit Plans	
Assumptions	**2012**	**2011**	**2012**	**2011**
Discount Rate	3.95 %	4.55 %	3.95 %	4.75 %
Rate of Compensation Increase	4.50 % (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.

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 2012, the rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 11.5% per year, with an average increase of 4.50%.

Actuarial Assumptions for Net Periodic Benefit Costs

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

	Pension Plan		Other Postretirement Benefit Plans	
	2012	**2011**	**2012**	**2011**
Discount Rate	4.55%	5.05 %	4.75%	5.25 %
Expected Return on Plan Assets	7.25%	7.75 %	7.25%	7.50 %
Rate of Compensation Increase	4.50%	4.50 %	NA	NA

NA Not Applicable

The expected return on plan assets for 2012 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.

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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	2012	2011
Initial	7.00 %	7.50 %
Ultimate	5.00 %	5.00 %
Year Ultimate Reached	2020	2016

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

	1% Increase	1% Decrease
	(in thousands)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 595	$ (471)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	2,698	(2,037)

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, 2012, 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.

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Benefit Plan Obligations, Plan Assets and Funded Status as of December 31, 2012 and 2011

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	
	2012	2011	2012	2011
Change in Benefit Obligation	(in thousands)			
Benefit Obligation as of January 1	$ 121,375	$ 113,592	$ 59,861	$ 56,806
Service Cost	1,412	1,389	1,007	939
Interest Cost	5,465	5,757	2,836	2,913
Actuarial Loss	9,676	7,172	5,265	7,046
Plan Amendment Prior Service Credit	-	-	(16,984)	(5,440)
Benefit Payments	(9,034)	(6,535)	(3,597)	(3,366)
Participant Contributions	-	-	784	773
Medicare Subsidy	-	-	198	190
Benefit Obligation as of December 31	$ 128,894	$ 121,375	$ 49,370	$ 59,861
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1	$ 100,633	$ 88,666	$ 39,739	$ 40,766
Actual Gain (Loss) on Plan Assets	12,065	7,967	5,626	(248)
Company Contributions	4,902	10,535	2,282	1,814
Participant Contributions	-	-	784	773
Benefit Payments	(9,034)	(6,535)	(3,597)	(3,366)
Fair Value of Plan Assets as of December 31	$ 108,566	$ 100,633	$ 44,834	$ 39,739
Underfunded Status as of December 31	$ (20,328)	$ (20,742)	$ (4,536)	$ (20,122)

Amounts Recognized on the Balance Sheets as of December 31, 2012 and 2011

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2012	2011	2012	2011
	(in thousands)			
Accumulated Provision for Pensions and Benefits – Long-term Benefit Liability	$ (20,328)	$ (20,742)	$ (4,536)	$ (20,122)
Underfunded Status	$ (20,328)	$ (20,742)	$ (4,536)	$ (20,122)

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Amounts Included in Regulatory Assets as of December 31, 2012 and 2011

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2012	2011	2012	2011
Components	(in thousands)			
Net Actuarial Loss	$ 47,324	$ 45,998	$ 26,835	$ 25,941
Prior Service Cost (Credit)	195	279	(22,306)	(5,826)
Recorded as				
Regulatory Assets	$ 47,519	$ 46,277	$ 4,529	$ 20,115

Components of the change in amounts included in regulatory assets during the years ended December 31, 2012 and 2011 are as follows:

	Pension Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
	2012	2011	2012	2011
Components	(in thousands)			
Actuarial Loss During the Year	$ 5,003	$ 6,557	$ 2,461	$ 10,239
Prior Service Credit	-	-	(16,984)	(5,440)
Amortization of Actuarial Loss	(3,677)	(2,951)	(1,567)	(751)
Amortization of Prior Service Credit (Cost)	(84)	(150)	504	35
Change for the Year	$ 1,242	$ 3,456	$ (15,586)	$ 4,083

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Pension and Other Postretirement Plans' Assets

The following table presents the classification of pension plan assets within the fair value hierarchy as of December 31, 2012:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 30,243	$ -	$ -	$ -	$ 30,243	27.9 %
International	11,485	-	-	-	11,485	10.5 %
Real Estate Investment Trusts	2,094	-	-	-	2,094	1.9 %
Common Collective Trust - International	-	100	-	-	100	0.1 %
Subtotal - Equities	43,822	100	-	-	43,922	40.4 %
Fixed Income:						
Common Collective Trust - Debt	-	734	-	-	734	0.7 %
United States Government and Agency Securities	-	16,538	-	-	16,538	15.2 %
Corporate Debt	-	28,555	-	-	28,555	26.3 %
Foreign Debt	-	4,592	-	-	4,592	4.2 %
State and Local Government	-	1,017	-	-	1,017	0.9 %
Other - Asset Backed	-	823	-	-	823	0.8 %
Subtotal - Fixed Income	-	52,259	-	-	52,259	48.1 %
Real Estate	-	-	5,076	-	5,076	4.7 %
Alternative Investments	-	-	4,522	-	4,522	4.2 %
Securities Lending	-	1,857	-	-	1,857	1.7 %
Securities Lending Collateral (a)	-	-	-	(2,100)	(2,100)	(1.9)%
Cash and Cash Equivalents	-	2,907	-	-	2,907	2.7 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	123	123	0.1 %
Total	$ 43,822	$ 57,123	$ 9,598	$ (1,977)	$ 108,566	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay cash collateral received as part of the Securities Lending Program.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

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

	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
		(in thousands)		
Balance as of January 1, 2012	$ 149	$ 3,820	$ 3,750	$ 7,719
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	665	221	886
Relating to Assets Sold During the Period	(52)	-	107	55
Purchases and Sales	(97)	591	444	938
Transfers into Level 3	-	-	-	-
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2012	$ -	$ 5,076	$ 4,522	$ 9,598

The following table presents the classification of OPEB plan assets within the fair value hierarchy as of December 31, 2012:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 12,067	$ -	$ -	$ -	$ 12,067	26.9 %
International	14,426	-	-	-	14,426	32.2 %
Subtotal - Equities	26,493	-	-	-	26,493	59.1 %
Fixed Income:						
Common Collective Trust - Debt	-	2,074	-	-	2,074	4.6 %
United States Government and Agency Securities	-	2,350	-	-	2,350	5.2 %
Corporate Debt	-	4,427	-	-	4,427	9.9 %
Foreign Debt	-	748	-	-	748	1.7 %
State and Local Government	-	208	-	-	208	0.5 %
Other - Asset Backed	-	281	-	-	281	0.6 %
Subtotal - Fixed Income	-	10,088	-	-	10,088	22.5 %
Trust Owned Life Insurance:						
International Equities	-	1,473	-	-	1,473	3.3 %
United States Bonds	-	4,649	-	-	4,649	10.3 %
Cash and Cash Equivalents	1,775	326	-	-	2,101	4.7 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	30	30	0.1 %
Total	$ 28,268	$ 16,536	$ -	$ 30	$ 44,834	100.0 %

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

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

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 34,021	$ -	$ -	$ -	$ 34,021	33.8 %
International	9,327	-	-	-	9,327	9.3 %
Real Estate Investment Trusts	2,432	-	-	-	2,432	2.4 %
Common Collective Trust - International	-	3,004	-	-	3,004	3.0 %
Subtotal - Equities	45,780	3,004	-	-	48,784	48.5 %
Fixed Income:						
Common Collective Trust - Debt	-	614	-	-	614	0.6 %
United States Government and Agency Securities	-	13,231	-	-	13,231	13.2 %
Corporate Debt	-	23,028	149	-	23,177	23.0 %
Foreign Debt	-	4,459	-	-	4,459	4.4 %
State and Local Government	-	1,124	-	-	1,124	1.1 %
Other - Asset Backed	-	608	-	-	608	0.6 %
Subtotal - Fixed Income	-	43,064	149	-	43,213	42.9 %
Real Estate	-	-	3,820	-	3,820	3.8 %
Alternative Investments	-	-	3,750	-	3,750	3.7 %
Securities Lending	-	5,023	-	-	5,023	5.0 %
Securities Lending Collateral (a)	-	-	-	(5,514)	(5,514)	(5.5)%
Cash and Cash Equivalents	-	2,170	-	-	2,170	2.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	(613)	(613)	(0.6)%
Total	$ 45,780	$ 53,261	$ 7,719	$ (6,127)	$ 100,633	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay cash collateral received as part of the Securities Lending Program.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

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

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

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

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

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

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.

Accumulated Benefit Obligation	December 31, 2012	December 31, 2011
	(in thousands)	
Qualified Pension Plan	$ 127,325	$ 119,973
Total	$ 127,325	$ 119,973

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, 2012 and 2011 were as follows:

	Underfunded Pension Plans 2012	Underfunded Pension Plans 2011
	(in thousands)	
Projected Benefit Obligation	$ 128,894	$ 121,375
Accumulated Benefit Obligation	$ 127,325	$ 119,973
Fair Value of Plan Assets	108,566	100,633
Underfunded Accumulated Benefit Obligation	$ (18,759)	$ (19,340)

Estimated Future Benefit Payments and Contributions

KPCo expects contributions and payments for the pension plans of $2.3 million during 2013. 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. In November 2012, changes to the retiree medical coverage were announced. Effective for retirements after December 2012, contributions to retiree medical coverage will be capped reducing exposure to future medical cost inflation. Effective for employees hired after December 2013, retiree medical coverage will not be provided. In December 2011, the prescription drug plan was amended for certain participants. The impact of the changes is reflected in the Benefit Plan Obligation table as plan amendments. 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:

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	Estimated Payments	
	Pension Plans	Other Postretirement Benefit Plans
	(in thousands)	
2013	$ 7,351	$ 3,418
2014	7,491	3,610
2015	7,850	3,873
2016	7,912	4,165
2017	8,272	4,487
Years 2018 to 2022, in Total	44,673	26,618

Components of Net Periodic Benefit Cost

The following table provides the components of net periodic benefit cost for the years ended December 31, 2012 and 2011:

	Pension Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
	2012	2011	2012	2011
	(in thousands)			
Service Cost	$ 1,412	$ 1,389	$ 1,007	$ 939
Interest Cost	5,465	5,757	2,836	2,913
Expected Return on Plan Assets	(7,392)	(7,351)	(2,911)	(3,029)
Amortization of Prior Service Cost (Credit)	84	150	(504)	(35)
Amortization of Net Actuarial Loss	3,677	2,951	1,567	751
Net Periodic Benefit Cost	3,246	2,896	1,995	1,539
Capitalized Portion	(1,438)	(1,121)	(884)	(596)
Net Periodic Benefit Cost Recognized as Expense	$ 1,808	$ 1,775	$ 1,111	$ 943

Estimated amounts expected to be amortized to net periodic benefit costs (credits) and the impact on the balance sheet during 2013 are shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in thousands)	
Net Actuarial Loss	$ 4,360	$ 1,724
Prior Service Cost (Credit)	42	(2,021)
Total Estimated 2013 Amortization	$ 4,402	$ (297)
Expected to be Recorded as		
Regulatory Asset	$ 4,402	$ (297)
Total	$ 4,402	$ (297)

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American Electric Power System Retirement Savings Plan

KPCo participates in an AEP sponsored defined contribution retirement savings plan, the American Electric Power System Retirement Savings Plan, for substantially all employees. This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for matching contributions. The matching contributions to the plan are 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions. The cost for matching contributions totaled $1.4 million in 2012 and $1.4 million in 2011.

6. BUSINESS SEGMENTS

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

7. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

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

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

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

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

The following table represents the gross notional volume of KPCo's outstanding derivative contracts as of December 31, 2012 and 2011:

Notional Volume of Derivative Instruments

	Volume		
	December 31,		
Primary Risk Exposure	**2012**	**2011**	**Unit of Measure**
	(in thousands)		
Commodity:			
Power	18,838	35,858	MWhs
Coal	247	783	Tons
Natural Gas	2,018	1,676	MMBtus
Heating Oil and Gasoline	269	274	Gallons
Interest Rate	$ 4,836	$ 6,566	USD

Fair Value Hedging Strategies

AEPSC, on behalf of KPCo, enters into interest rate derivative transactions as part of an overall strategy to manage the mix of fixed-rate and floating-rate debt. Certain interest rate derivative transactions effectively modify KPCo's exposure to interest rate risk by converting a portion of KPCo's fixed-rate debt to a floating rate. Provided specific criteria are met, these interest rate derivatives are designated as fair value hedges.

Cash Flow Hedging Strategies

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

KPCo's vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of KPCo, enters into financial heating oil and gasoline derivative contracts in order to mitigate price risk of future fuel purchases. For disclosure purposes, these contracts are included with other hedging activities as "Commodity." KPCo does not hedge all fuel price risk.

AEPSC, on behalf of KPCo, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify exposure to interest rate risk by converting a portion of floating-rate debt to a fixed rate. AEPSC, on behalf of KPCo, also enters into interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. The forecasted fixed-rate debt offerings have a high probability of occurrence as the proceeds will be used to fund existing debt maturities and projected capital expenditures. KPCo does not hedge all interest rate exposure.

At times, KPCo is exposed to foreign currency exchange rate risks primarily when KPCo purchases certain fixed assets from foreign suppliers. In accordance with AEP's risk management policy, AEPSC, on behalf of KPCo, may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. KPCo does not hedge all foreign currency exposure.

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

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

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

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the December 31, 2012 and 2011 balance sheets, KPCo netted $253 thousand and $908 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $2.2 million and $6.1 million, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following tables represent the gross fair value impact of derivative activity on the balance sheets as of December 31, 2012 and 2011:

Fair Value of Derivative Instruments
December 31, 2012

	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (d)
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate (a)			
			(in thousands)			
Derivative Instrument Assets	$ 37,565	$ -	$ -	$ 37,565	$ (24,571)	$ 12,994
Long-Term Portion of Derivative Instrument Assets	12,117	-	-	12,117	(5,276)	6,841
Derivative Instrument Assets – Hedges	-	115	-	115	(52)	63
Long-Term Portion of Derivative Instrument Assets – Hedges	-	43	-	43	(2)	41
Derivative Instrument Liabilities	33,275	-	-	33,275	(26,527)	6,748
Long-Term Portion of Derivative Instrument Liabilities	9,469	-	-	9,469	(5,852)	3,617
Derivative Instrument Liabilities – Hedges	-	324	-	324	(52)	272
Long-Term Portion of Derivative Instrument Liabilities – Hedges	-	85	-	85	(2)	83

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Fair Value of Derivative Instruments
December 31, 2011

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 (c)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (d)
			(in thousands)			
Derivative Instrument Assets	$ 70,356	$ -	$ -	$ 70,356	$ (53,759)	$ 16,597
Long-Term Portion of Derivative Instrument Assets	21,107	-	-	21,107	(12,812)	8,295
Derivative Instrument Assets – Hedges	-	239	-	239	(148)	91
Long-Term Portion of Derivative Instrument Assets – Hedges	-	18	-	18	(13)	5
Derivative Instrument Liabilities	67,155	-	-	67,155	(59,313)	7,842
Long-Term Portion of Derivative Instrument Liabilities	17,362	-	-	17,362	(14,689)	2,673
Derivative Instrument Liabilities – Hedges	-	669	-	669	(148)	521
Long-Term Portion of Derivative Instrument Liabilities – Hedges	-	74	-	74	(13)	61

(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) Amounts primarily include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging." Amounts also include de-designated risk management contracts.
(d) 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, 2012 and 2011:

Amount of Gain (Loss) Recognized on
Risk Management Contracts

Location of Gain (Loss)	Years Ended December 31, 2012	2011
	(in thousands)	
Operating Revenues	$ (1,597)	$ 2,279
Operation Expenses	-	(3)
Regulatory Assets (a)	-	93
Regulatory Liabilities (a)	1,047	(1,158)
Total Gain (Loss) on Risk Management Contracts	$ (550)	$ 1,211

(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.

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

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in Operating 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 Operating Revenues or Operation Expenses on KPCo's statements of income depending on the relevant facts and circumstances. However, unrealized and some realized gains and losses for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains), in accordance with the accounting guidance for "Regulated Operations."

Accounting for Fair Value Hedging Strategies

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

KPCo records realized and unrealized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest on Long-Term Debt on KPCo's statements of income. During 2012 and 2011, KPCo did not designate any fair value hedging strategies.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), KPCo initially reports the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income 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, coal and natural gas designated as cash flow hedges are included in Operating Revenues or Operation Expenses on the statements of income, or in regulatory assets or regulatory liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During 2012 and 2011, KPCo designated power, coal and natural gas derivatives as cash flow hedges.

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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. During 2012 and 2011, KPCo designated heating oil and gasoline derivatives as cash flow hedges.

KPCo reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income 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 2012 and 2011, KPCo did not designate any interest rate derivatives as cash flow hedges.

The accumulated gains or losses related to foreign currency hedges are reclassified from Accumulated Other Comprehensive Income on KPCo's balance sheets into Depreciation Expense on the statements of income over the depreciable lives of the fixed assets that were designated as the hedged items in qualifying foreign currency hedging relationships. During 2012 and 2011, KPCo did not designate any foreign currency derivatives as cash flow hedges.

During 2012 and 2011, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

The following tables provide details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income on the balance sheets and the reasons for changes in cash flow hedges for the years ended December 31, 2012 and 2011. All amounts in the following tables are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2012

	Commodity	Interest Rate	Total
		(in thousands)	
Balance in AOCI as of December 31, 2011	$ (283)	$ (342)	$ (625)
Changes in Fair Value Recognized in AOCI	(246)	-	(246)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Operating Revenues	(16)	-	(16)
Operation Expenses	422	-	422
Interest on Long-term Debt	-	60	60
Utility Plant	(4)	-	(4)
Balance in AOCI as of December 31, 2012	$ (127)	$ (282)	$ (409)

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Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2011

	Commodity	Interest Rate (in thousands)	Total
Balance in AOCI as of December 31, 2010	$ (48)	$ (403)	$ (451)
Changes in Fair Value Recognized in AOCI	(431)	-	(431)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Operating Revenues	205	-	205
Operation Expenses	19	-	19
Maintenance Expenses	(37)	-	(37)
Interest on Long-term Debt	-	61	61
Utility Plant	(47)	-	(47)
Regulatory Assets (a)	56	-	56
Balance in AOCI as of December 31, 2011	$ (283)	$ (342)	$ (625)

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

Cash flow hedges included in Accumulated Other Comprehensive Income on the balance sheets as of December 31, 2012 and 2011 were:

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2012

	Commodity	Interest Rate (in thousands)	Total
Hedging Assets (a)	$ 63	$ -	$ 63
Hedging Liabilities (a)	272	-	272
AOCI Loss Net of Tax	(127)	(282)	(409)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(100)	(60)	(160)

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

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

(a) Hedging Assets and Hedging Liabilities are included in Derivative Instrument Assets – Hedges and Derivative Instrument Liabilities – Hedges on the 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, 2012, the maximum length of time that KPCo is hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") its exposure to variability in future cash flows related to forecasted transactions is 17 months.

Credit Risk

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

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

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, KPCo is obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. KPCo has not experienced a downgrade below investment grade. The following table represents: (a) KPCo's fair value of such derivative contracts, (b) the amount of collateral KPCo would have been required to post for all derivative and non-derivative contracts if the credit ratings had declined below investment grade and (c) how much was attributable to RTO and ISO activities as of December 31, 2012 and 2011:

	December 31, 2012	December 31, 2011
	(in thousands)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 432	$ 2,117
Amount of Collateral KPCo Would Have Been Required to Post	741	1,314
Amount Attributable to RTO and ISO Activities	703	1,314

As of December 31, 2012 and 2011, KPCo was not required to post any collateral.

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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, 2012 and 2011:

	December 31, 2012	December 31, 2011
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 9,907	$ 16,265
Amount of Cash Collateral Posted	365	1,715
Additional Settlement Liability if Cross Default Provision is Triggered	6,041	5,841

8. 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, 2012 and 2011 are summarized in the following table:

	December 31, 2012		December 31, 2011	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 549,222	$ 708,566	$ 549,055	$ 685,628

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.

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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, 2012 and 2011. 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, 2012

	Level 1	Level 2	Level 3	Other	Total
			(in thousands)		
Derivative Instrument Assets					
Risk Management Commodity Contracts (a) (b)	$ 833	$ 33,315	$ 3,417	$ (24,571)	$ 12,994
Derivative Instrument Assets - Hedges					
Cash Flow Hedges – Commodity (a)	-	103	-	(40)	63
Total Assets	$ 833	$ 33,418	$ 3,417	$ (24,611)	$ 13,057
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 392	$ 31,665	$ 1,218	$ (26,527)	$ 6,748
Derivative Instrument Liabilities - Hedges					
Cash Flow Hedges – Commodity (a)	-	312	-	(40)	272
Total Liabilities	$ 392	$ 31,977	$ 1,218	$ (26,567)	$ 7,020

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Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2011

	Level 1	Level 2	Level 3	Other	Total
			(in thousands)		
Derivative Instrument Assets					
Risk Management Commodity Contracts (a) (b)	$ 990	$ 63,922	$ 5,379	$ (54,018)	$ 16,273
Dedesignated Risk Management Contracts (c)	-	-	-	324	324
Total Derivative Instrument Assets	990	63,922	5,379	(53,694)	16,597
Derivative Instrument Assets - Hedges					
Cash Flow Hedges – Commodity (a)	-	232	-	(141)	91
Total Assets	$ 990	$ 64,154	$ 5,379	$ (53,835)	$ 16,688
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 536	$ 61,607	$ 4,947	$ (59,248)	$ 7,842
Derivative Instrument Liabilities - Hedges					
Cash Flow Hedges – Commodity (a)	-	646	16	(141)	521
Total Liabilities	$ 536	$ 62,253	$ 4,963	$ (59,389)	$ 8,363

(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.
(c) Represents contracts that were originally MTM but were subsequently elected as normal under the accounting guidance for "Derivatives and Hedging." At the time of the normal election, the MTM value was frozen and no longer fair valued. This MTM value will be amortized into revenues over the remaining life of the contracts.

There have been no transfers between Level 1 and Level 2 during the years ended December 31, 2012 and 2011.

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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, 2012	**Net Risk Management Assets (Liabilities) (in thousands)**
Balance as of December 31, 2011	$ 416
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(1,071)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	5
Purchases, Issuances and Settlements (c)	2,282
Transfers into Level 3 (d) (e)	309
Transfers out of Level 3 (e) (f)	(434)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	692
Balance as of December 31, 2012	$ 2,199

Year Ended December 31, 2011	**Net Risk Management Assets (Liabilities) (in thousands)**
Balance as of December 31, 2010	$ 1,073
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(454)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(16)
Purchases, Issuances and Settlements (c)	336
Transfers into Level 3 (d) (e)	524
Transfers out of Level 3 (e) (f)	(635)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(412)
Balance as of December 31, 2011	$ 416

(a) Included in revenues on KPCo's statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Represents the settlement of risk management commodity contracts for the reporting period.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(f) Represents existing assets or liabilities that were previously categorized as Level 3.
(g) Relates to the net gains (losses) of those contracts that are not reflected on KPCo's statements of income. These net gains (losses) are recorded as regulatory assets/liabilities.

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The following table quantifies the significant unobservable inputs used in developing the fair value of Level 3 positions as of December 31, 2012:

	Fair Value		Valuation	Significant	Forward Price Range	
	Assets	**Liabilities**	**Technique**	**Unobservable Input (a)**	**Low**	**High**
	(in thousands)					
Energy Contracts	$ 3,067	$ 786	Discounted Cash Flow	Forward Market Price	$ 9.40	$ 68.80
FTRs	350	432	Discounted Cash Flow	Forward Market Price	(3.21)	14.79
Total	$ 3,417	$ 1,218				

(a) Represents market prices in dollars per MWH.

9. INCOME TAXES

The details of income taxes as reported are as follows:

	Years Ended December 31,	
	2012	**2011**
	(in thousands)	
Charged (Credited) to Operating Expenses, Net:		
Current	$ 13,342	$ 7,367
Deferred		
Deferred Investment Tax Credits	10,184	17,966
	(278)	(359)
Total	23,248	24,974
Charged (Credited) to Nonoperating Income, Net:		
Current	(742)	(31)
Deferred	(104)	(199)
Total	(846)	(230)
Total Income Tax Expense	$ 22,402	$ 24,744

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

	Years Ended December 31, 2012	2011
	(in thousands)	
Net Income	$ 50,978	$ 42,374
Income Tax Expense	22,402	24,744
Pretax Income	$ 73,380	$ 67,118
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 25,683	$ 23,491
Increase (Decrease) in Income Taxes resulting from the following items:		
Depreciation	2,382	2,563
Allowance for Funds Used During Construction	(894)	(818)
Removal Costs	(3,885)	(2,010)
Investment Tax Credits, Net	(278)	(359)
State and Local Income Taxes, Net	1,516	2,145
Parent Company Loss Benefit	(1,292)	(462)
Other	(830)	194
Income Tax Expense	$ 22,402	$ 24,744
Effective Income Tax Rate	30.5 %	36.9 %

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

	December 31, 2012	2011
	(in thousands)	
Deferred Tax Assets	$ 28,380	$ 34,383
Deferred Tax Liabilities	(385,153)	(375,379)
Net Deferred Tax Liabilities	$ (356,773)	$ (340,996)
Property Related Temporary Differences	$ (271,200)	$ (263,320)
Amounts Due from Customers for Future Federal Income Taxes	(29,800)	(28,430)
Deferred State Income Taxes	(42,345)	(41,595)
Deferred Income Taxes on Other Comprehensive Loss	220	337
Accrued Pensions	8,810	8,771
Regulatory Assets	(20,604)	(25,686)
All Other, Net	(1,854)	8,927
Net Deferred Tax Liabilities	$ (356,773)	$ (340,996)

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AEP System Tax Allocation Agreement

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

Federal and State Income Tax Audit Status

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2009. KPCo and other AEP subsidiaries completed the examination of the years 2007 and 2008 in April 2011 and settled all outstanding issues on appeal for the years 2001 through 2006 in October 2011. The settlements did not have a material impact on KPCo and other AEP subsidiaries' net income, cash flows or financial condition. The IRS examination of years 2009 and 2010 started in October 2011. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to 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. Management believes that previously filed tax returns have positions that may be challenged by these tax authorities. However, management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income. With few exceptions, KPCo is no longer subject to state or local income tax examinations by tax authorities for years before 2008.

Tax Credit Carryforward

The AEP System sustained consolidated federal net income tax operating losses in 2011 and 2009 along with lower federal taxable income, resulting in unused federal income tax credits of $160 thousand, not all of which have an expiration date. As of December 31, 2012, KPCo has federal general business tax credit carryforwards of $147 thousand. If these credits are not utilized, the federal general business tax credits will expire in the years 2028 through 2031.

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

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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, interest income and reversal of prior period interest expense:

	Years Ended December 31, 2012	2011
	(in thousands)	
Interest Expense	$ 23	$ 193
Interest Income	-	1,849
Reversal of Prior Period Interest Charges	-	284

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

	December 31, 2012	2011
	(in thousands)	
Accrual for Receipt of Interest	$ 1	$ -
Accrual for Payment of Interest and Penalties	92	2

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

	2012	2011
	(in thousands)	
Balance as of January 1,	$ 1,608	$ 2,711
Increase - Tax Positions Taken During a Prior Period	-	1,604
Decrease - Tax Positions Taken During a Prior Period	(93)	(1,586)
Increase - Tax Positions Taken During the Current Year	-	-
Decrease - Tax Positions Taken During the Current Year	-	-
Decrease - Settlements with Taxing Authorities	(182)	(99)
Decrease - Lapse of the Applicable Statute of Limitations	-	(1,022)
Balance as of December 31,	$ 1,333	$ 1,608

The total amount of unrecognized tax benefits (costs) that, if recognized, would affect the effective tax rate is $0 thousand and $(4) thousand for 2012 and 2011, respectively. Management believes there will be no significant net increase or decrease in unrecognized tax benefits within 12 months of the reporting date.

Federal Tax Legislation

In December 2011, the U.S. Treasury Department issued guidance regarding the deduction and capitalization of expenditures related to tangible property. The guidance was in the form of proposed and temporary regulations and generally is effective for tax years beginning in 2012. In November 2012, the effective date was moved to tax years beginning in 2014. Further, the notice stated that the U. S. Treasury Department anticipates that the final regulations will contain changes from the temporary regulations. Management will evaluate the impact of these regulations once they are issued.

The American Taxpayer Relief Act of 2012 (the 2012 Act) was enacted in January 2013. Included in the 2012 Act was a one-year extension of the 50% bonus depreciation. The 2012 Act also retroactively extended the life of research and development, employment and several energy tax credits, which expired at the end of 2011. The enacted provisions will not materially impact KPCo's net income or financial condition but are expected to have a favorable impact on cash flows in 2013.

State Tax Legislation

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

During the third quarter of 2012, the state of West Virginia achieved certain minimum levels of shortfall reserve funds. As a result, the West Virginia corporate income tax rate will be reduced from 7.75% to 7.0% in 2013. The enacted provisions will not materially impact KPCo's net income, cash flows or financial condition.

10. LEASES

Leases of property, plant and equipment are for periods up to 20 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to Operation Expenses and Maintenance Expenses in accordance with rate-making treatment for regulated operations. The components of rental costs are as follows:

Lease Rental Costs	Years Ended December 31, 2012	2011
	(in thousands)	
Net Lease Expense on Operating Leases	$ 1,133	$ 830
Amortization of Capital Leases	1,442	1,690
Interest on Capital Leases	242	311
Total Lease Rental Costs	$ 2,817	$ 2,831

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

	December 31, 2012	2011
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Production	$ 683	$ 683
Other Property, Plant and Equipment	4,500	5,047
Total Property, Plant and Equipment Under Capital Leases	5,183	5,730
Accumulated Amortization	2,105	1,890
Net Property, Plant and Equipment Under Capital Leases	$ 3,078	$ 3,840
Obligations Under Capital Leases		
Noncurrent Liability	$ 1,674	$ 2,387
Liability Due Within One Year	1,404	1,453
Total Obligations Under Capital Leases	$ 3,078	$ 3,840

Future minimum lease payments consisted of the following as of December 31, 2012:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2013	$ 1,530	$ 1,314
2014	497	1,131
2015	444	994
2016	323	933
2017	251	734
Later Years	366	1,433
Total Future Minimum Lease Payments	3,411	$ 6,539
Less Estimated Interest Element	333	
Estimated Present Value of Future Minimum Lease Payments	$ 3,078	

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, 2012, the maximum potential loss for these lease agreements was approximately $1 million assuming the fair value of the equipment is zero at the end of the lease term.

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11. FINANCING ACTIVITIES

Long-term Debt

There are certain limitations on establishing liens against KPCo's assets under its indentures. None of the long-term debt obligations of KPCo have been guaranteed or secured by AEP or any of its affiliates.

The following details long-term debt outstanding as of December 31, 2012 and 2011:

Type of Debt	Maturity	Weighted Average Interest Rate as of December 31, 2012	Interest Rate Ranges as of December 31, 2012	Interest Rate Ranges as of December 31, 2011	Outstanding as of December 31, 2012	Outstanding as of December 31, 2011
					(in thousands)	
Senior Unsecured Notes	2017-2039	6.40%	5.625%-8.13%	5.625%-8.13%	$ 530,000	$ 530,000
Notes Payable - Affiliated	2015	5.25%	5.25%	5.25%	20,000	20,000
Unamortized Discount, Net					(778)	(945)
Total Long-term Debt Outstanding					$ 549,222	$ 549,055

Long-term debt outstanding as of December 31, 2012 is payable as follows:

	2013	2014	2015	2016	2017	After 2017	Total
				(in thousands)			
Principal Amount	$ -	$ -	$ 20,000	$ -	$ 325,000	$ 205,000	$ 550,000
Unamortized Discount, Net							(778)
Total Long-term Debt Outstanding							$ 549,222

Dividend Restrictions

Federal Power Act

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

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Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of the 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 approved in a regulatory order. The amount of outstanding borrowings from the Utility Money Pool as of December 31, 2012 is included in Notes Payable to Associated Companies on the balance sheets. The amount of outstanding loans to the Utility Money Pool as of December 31, 2011 is included in Notes Receivable from Associated Companies on the balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the years ended December 31, 2012 and 2011 are described in the following table:

Year	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Loans (Borrowings) to/from Utility Money Pool as of December 31,	Authorized Short-Term Borrowing Limit
			(in thousands)			
2012	$ 13,359	$ 80,205	$ 9,200	$ 46,187	$ (13,359)	$ 250,000
2011	-	117,473	-	89,182	70,332	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, 2012 and 2011 are summarized in the following table:

Year Ended December 31,	Maximum Interest Rates for Funds Borrowed from Utility Money Pool	Minimum Interest Rates for Funds Borrowed from Utility Money Pool	Maximum Interest Rates for Funds Loaned to Utility Money Pool	Minimum Interest Rates for Funds Loaned to Utility Money Pool	Average Interest Rates for Funds Borrowed from Utility Money Pool	Average Interest Rates for Funds Loaned to Utility Money Pool
2012	0.42 %	0.42 %	0.56 %	0.39 %	0.42 %	0.48 %
2011	- %	- %	0.56 %	0.06 %	- %	0.35 %

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 the 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, 2012 and 2011:

	Years Ended December 31, 2012	2011
	(in thousands)	
Interest Expense	$ 1	$ -
Interest Income	222	318

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.

In 2012, AEP Credit renewed its receivables securitization agreement. The agreement provides a commitment of $700 million from bank conduits to finance receivables from AEP Credit. A commitment of $385 million expires in June 2013 and the remaining commitment of $315 million expires in June 2015.

KPCo's amount of accounts receivable and accrued unbilled revenues sold under the sale of receivables agreement was $46 million and $52 million as of December 31, 2012 and 2011, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold were $2 million for each of the years ended December 31, 2012 and 2011.

KPCo's proceeds on the sale of receivables to AEP Credit were $517 million and $579 million for the years ended December 31, 2012 and 2011, respectively.

12. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "AEP System Tax Allocation Agreement" section of Note 9 in addition to "Utility Money Pool – AEP System" and "Sale of Receivables – AEP Credit" sections of Note 11.

Interconnection Agreement

APCo, I&M, KPCo, OPCo and AEPSC are parties to the Interconnection Agreement, which defines the sharing of costs and benefits associated with the respective generating plants. This sharing is based upon each AEP utility subsidiary's MLR and is calculated monthly on the basis of each AEP utility subsidiary's maximum peak demand in relation to the sum of the maximum peak demands of all four AEP utility subsidiaries during the preceding 12 months. In addition, APCo, I&M, KPCo and OPCo are parties to the AEP System Interim Allowance Agreement, which provides, among other things, for the transfer of SO_2 allowances associated with the transactions under the Interconnection Agreement.

In October 2012, the AEP East Companies submitted several filings with the FERC seeking approval to fully separate OPCo's generating assets from its distribution and transmission operations. Additionally, the AEP East Companies asked the FERC to terminate the existing Interconnection Agreement and to approve a new Power Coordination Agreement among APCo, I&M and KPCo. A decision from the FERC is expected in mid-2013. See "Corporate Separation and Termination of Interconnection Agreement" section of Note 2.

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NOTES TO FINANCIAL STATEMENTS (Continued)

Power, gas and risk management activities are conducted by AEPSC and profits and losses are allocated under the SIA to members of the Interconnection Agreement, PSO and SWEPCo. Risk management activities involve the purchase and sale of electricity and gas under physical forward contracts at fixed and variable prices. In addition, the risk management of electricity, and to a lesser extent gas contracts, includes exchange traded futures and options and OTC options and swaps. The majority of these transactions represent physical forward contracts in the AEP System's traditional marketing area and are typically settled by entering into offsetting contracts. In addition, AEPSC enters into transactions for the purchase and sale of electricity and gas options, futures and swaps, and for the forward purchase and sale of electricity outside of the AEP System's traditional marketing area.

CSW Operating Agreement

PSO, SWEPCo and AEPSC are parties to a Restated and Amended Operating Agreement originally dated as of January 1, 1997 (CSW Operating Agreement), which was approved by the FERC. The CSW Operating Agreement requires PSO and SWEPCo to maintain adequate annual planning reserve margins and requires that capacity in excess of the required margins be made available for sale to other operating companies as capacity commitments. Parties are compensated for energy delivered to recipients based upon the deliverer's incremental cost plus a portion of the recipient's savings realized by the purchaser that avoids the use of more costly alternatives. Revenues and costs arising from third party sales are generally shared based on the amount of energy PSO or SWEPCo contributes that is sold to third parties.

System Integration Agreement (SIA)

The SIA provides for the integration and coordination of AEP East Companies' and AEP West Companies' zones. This includes joint dispatch of generation within the AEP System and the distribution, between the two zones, of costs and benefits associated with the transfers of power between the two zones (including sales to third parties and risk management and trading activities). The SIA is designed to function as an umbrella agreement in addition to the Interconnection Agreement and the CSW Operating Agreement, each of which controls the distribution of costs and benefits within a zone.

Power generated, allocated or provided under the Interconnection Agreement or CSW Operating Agreement is primarily sold to customers at rates approved by the public utility commission in the jurisdiction of sale.

Under both the Interconnection Agreement and CSW Operating Agreement, power generated that is not needed to serve the AEP System's native load is sold in the wholesale market by AEPSC on behalf of the generating subsidiary.

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NOTES TO FINANCIAL STATEMENTS (Continued)

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, natural gas contracts with AEPES and other revenues for the years ended December 31, 2012 and 2011:

Related Party Revenues	Years Ended December 31, 2012	2011
	(in thousands)	
Sales under Interconnection Agreement	$ 32,513	$ 67,170
Direct Sales to West Affiliates	64	314
Transmission Agreement Sales	3,022	4,480
Natural Gas Contracts with AEPES	-	32
Other Revenues	270	263

The following table shows the purchased power expenses incurred from purchases under the Interconnection Agreement and from affiliates for the years ended December 31, 2012 and 2011:

Related Party Purchases	Years Ended December 31, 2012	2011
	(in thousands)	
Purchases under Interconnection Agreement	$ 125,726	$ 115,583
Direct Purchases from West Affiliates	11	51
Purchases from AEGCo	102,371	98,031

System Transmission Integration Agreement

AEP's System Transmission Integration Agreement provides for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEP East Companies' and AEP West Companies' zones. Similar to the SIA, the System Transmission Integration Agreement functions as an umbrella agreement in addition to the Transmission Agreement (TA) and the Transmission Coordination Agreement (TCA). The System Transmission Integration Agreement contains two service schedules that govern:

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

The System Transmission Integration Agreement anticipates that additional service schedules may be added as circumstances warrant.

APCo, I&M, KPCo and OPCo are parties to a new TA, effective November 2010, defining how they share the costs associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345 kV and above) and certain facilities operated at lower voltages (138 kV and above). The new TA was phased-in for retail rates, added KGPCo and WPCo as parties to the agreement and changed the allocation method. KPCo's net charges recorded as a result of the new TA for the years ended December 31, 2012 and 2011 were $1.1 million and $410 thousand, respectively, and were recorded in Operation Expenses.

PSO, SWEPCo and AEPSC are parties to the TCA, dated January 1, 1997, revised 1999 and 2011, as restated and amended, by and among PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two AEP utility subsidiaries. The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with overseeing the coordinated planning of the transmission facilities of the parties to the agreement.

Fuel Agreement between OPCo and AEPES

OPCo and National Power Cooperative, Inc. (NPC) have an agreement whereby OPCo operates a 500 MW gas plant owned by NPC (Mone Plant). AEPES entered into a fuel management agreement with OPCo and NPC to manage and procure fuel for the Mone Plant. The gas purchased by AEPES and used in generation is first sold to OPCo then allocated to the AEP East Companies, who have an agreement to purchase 100% of the available generating capacity from the plant through May 2014. KPCo's related purchases of gas managed by AEPES were $173 thousand and $183 thousand for the years ended December 31, 2012 and 2011, respectively. These purchases are included in Operation Expenses.

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 $74 thousand and $122 thousand in 2012 and 2011, respectively, 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 $277 thousand and $298 thousand for the years ended December 31, 2012 and 2011, respectively.

Affiliate Railcar Agreement

KPCo has an agreement providing for the use of its affiliates' leased or owned railcars when available. The agreement specifies that the company using the railcar will be billed, at cost, by the company furnishing the railcar. KPCo recorded these costs in Fuel Stock on the balance sheets and such costs are recoverable from customers. The following table shows the net effect of the railcar agreement on KPCo's balance sheets:

Billing Company	December 31, 2012	December 31, 2011
	(in thousands)	
APCo	$ 98	$ 289
OPCo	41	355

Purchases from OVEC under the Interconnection Agreement

In 2011, the parties to the Interconnection Agreement purchased power from OVEC to serve off-system sales and retail sales. These purchases are reported in Operation Expenses on the statement of income. KPCo recorded $4.5 million in expense for the year ended December 31, 2011.

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, that were recorded at net book value, for the years ended December 31, 2012 and 2011:

	Years Ended December 31, 2012	Years Ended December 31, 2011
	(in thousands)	
Sales	$ 657	$ 404
Purchases	601	2,188

The amounts above are recorded in Utility Plant on the balance sheets.

Global Borrowing Notes

As of December 31, 2012 and 2011, AEP has an intercompany note in place with KPCo. The debt is reflected in Advances from Associated Companies on the balance sheets. KPCo accrues interest for its share of the global borrowing and remits the interest to AEP.

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, 2012 and 2011 were $35 million and $32 million, respectively.

13. 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 the annual composite depreciation rates by functional class:

Year	Steam	Transmission	Distribution	General
		(in percentages)		
2012	3.8	1.6	3.4	7.2
2011	3.8	1.7	3.5	8.2

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

Asset Retirement Obligations (ARO)

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

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The following is a reconciliation of the 2012 and 2011 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)			
2012	$ 3,772	$ 320	$ -	$ (190)	$ -	$ 3,902
2011	4,186	346	-	(295)	(465)	3,772

14. COST REDUCTION PROGRAM

2012 Sustainable Cost Reductions

In April 2012, management initiated a process to identify strategic repositioning opportunities and efficiencies that will result in sustainable cost savings. Management selected a consulting firm to conduct an organizational and process evaluation and a second firm to evaluate current employee benefit programs. The process resulted in involuntary severances and is expected to be completed by the end of the first quarter of 2013. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

KPCo recorded a charge to expense during 2012 related primarily to severance benefits for the sustainable cost reductions initiative.

Expense Allocation from AEPSC	Incurred	Settled	Remaining Balance as of December 31, 2012
	(in thousands)		
$ 1,128	$ 586	$ (1,217)	$ 497

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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				
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				
5	Balance of Account 219 at End of Preceding Quarter/Year				
6	Balance of Account 219 at Beginning of Current Year				
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				
10	Balance of Account 219 at End of Current Quarter/Year				

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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	(402,810)	(48,319)	(451,129)		
2	60,421	196,024	256,445		
3		(430,560)	(430,560)		
4	60,421	(234,536)	(174,115)	42,373,948	42,199,833
5	(342,389)	(282,855)	(625,244)		
6	(342,389)	(282,855)	(625,244)		
7	60,422	402,135	462,557		
8		(246,193)	(246,193)		
9	60,422	155,942	216,364	50,978,453	51,194,817
10	(281,967)	(126,913)	(408,880)		

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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)	1,678,058,120	1,678,058,120
4	Property Under Capital Leases	3,078,177	3,078,177
5	Plant Purchased or Sold		
6	Completed Construction not Classified	68,475,711	68,475,711
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	1,749,612,008	1,749,612,008
9	Leased to Others		
10	Held for Future Use	7,436,551	7,436,551
11	Construction Work in Progress	44,281,292	44,281,292
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	1,801,329,851	1,801,329,851
14	Accum Prov for Depr, Amort, & Depl	622,134,082	622,134,082
15	Net Utility Plant (13 less 14)	1,179,195,769	1,179,195,769
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	601,239,741	601,239,741
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	20,894,341	20,894,341
22	Total In Service (18 thru 21)	622,134,082	622,134,082
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)	622,134,082	622,134,082

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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
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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)		
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)		
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)		
10	SUBTOTAL (Total 8 & 9)		
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)		
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
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)		

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NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year: Amortization (d)	Changes during Year: Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)	Line No.
			1
			2
			3
			4
			5
			6
			7
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			9
			10
			11
			12
			13
			14
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			18
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			21
			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	04/11/2013	End of 2012/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	15,443,872	3,447,673
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	15,496,791	3,447,673
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,076,546	
9	(311) Structures and Improvements	42,537,537	810,182
10	(312) Boiler Plant Equipment	365,369,487	9,019,956
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	110,041,344	773,195
13	(315) Accessory Electric Equipment	16,095,400	428,637
14	(316) Misc. Power Plant Equipment	8,021,614	27,170
15	(317) Asset Retirement Costs for Steam Production	3,614,563	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	546,756,491	11,059,140
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)	546,756,491	11,059,140

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	04/11/2013	End of 2012/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	27,952,149	1,310,322
49	(352) Structures and Improvements	6,572,015	24,324
50	(353) Station Equipment	158,379,009	11,975,706
51	(354) Towers and Fixtures	95,111,840	32,305
52	(355) Poles and Fixtures	55,616,949	15,013,450
53	(356) Overhead Conductors and Devices	112,771,806	7,983,240
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)	456,521,424	36,339,347
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	6,714,984	464,525
61	(361) Structures and Improvements	4,370,465	10,965
62	(362) Station Equipment	65,051,403	12,490,375
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	168,185,857	6,739,700
65	(365) Overhead Conductors and Devices	152,685,868	14,704,104
66	(366) Underground Conduit	5,472,298	325,991
67	(367) Underground Conductors and Devices	8,597,232	412,743
68	(368) Line Transformers	108,680,560	7,104,693
69	(369) Services	46,550,138	3,626,860
70	(370) Meters	24,160,936	2,223,928
71	(371) Installations on Customer Premises	18,691,050	1,560,073
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	3,043,605	192,837
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	612,204,396	49,856,794
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	20,061,747	1,336,708
88	(391) Office Furniture and Equipment	1,279,644	
89	(392) Transportation Equipment	14,768	
90	(393) Stores Equipment	155,695	4,200
91	(394) Tools, Shop and Garage Equipment	2,941,749	453,686
92	(395) Laboratory Equipment	141,764	
93	(396) Power Operated Equipment	5,931	
94	(397) Communication Equipment	6,905,515	163,407
95	(398) Miscellaneous Equipment	1,033,893	8,941
96	SUBTOTAL (Enter Total of lines 86 thru 95)	34,065,437	1,966,942
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)	34,146,492	1,966,942
100	TOTAL (Accounts 101 and 106)	1,665,125,594	102,669,896
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)	1,665,125,594	102,669,896

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	04/11/2013	End of 2012/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.
					1
					2
			52,919		3
1,210,428			17,681,117		4
1,210,428			17,734,036		5
					6
					7
			1,076,546		8
188,376			43,159,343		9
5,487,449			368,901,994		10
					11
513,877			110,300,662		12
133,162			16,390,875		13
19,532			8,029,252		14
			3,614,563		15
6,342,396			551,473,235		16
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6,342,396			551,473,235		46

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2013	Year/Period of Report End of 2012/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
			29,262,471		48
			6,596,339		49
1,197,113			169,157,602		50
675,189			94,468,956		51
553,877		-20,000	70,056,522		52
313,102		20,000	120,461,944		53
			11,590		54
			106,066		55
					56
					57
2,739,281			490,121,490		58
					59
			7,179,509		60
			4,381,430		61
1,141,864			76,399,914		62
					63
946,893			173,978,664		64
2,784,176			164,605,796		65
1,132			5,797,157		66
94,614			8,915,361		67
1,841,401			113,943,852		68
357,594			49,819,404		69
1,653,695			24,731,169		70
1,189,432			19,061,691		71
					72
62,663			3,173,779		73
					74
10,073,464			651,987,726		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			1,524,731		86
675,528			20,722,927		87
			1,279,644		88
			14,768		89
			159,895		90
			3,395,435		91
			141,764		92
			5,931		93
213,323			6,855,599		94
7,239			1,035,595		95
896,090			35,136,289		96
					97
			81,055		98
896,090			35,217,344		99
21,261,659			1,746,533,831		100
					101
					102
					103
21,261,659			1,746,533,831		104

Name of Respondent Kentucky Power Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2013	Year/Period of Report 2012/Q4

FOOTNOTE DATA

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 Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2013	Year/Period of Report End of 2012/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					
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45					
46					
47	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	04/11/2013	End of 2012/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)	08/17/82		6,778,355
3				
4	Ramey Substation (4205)	10/1/09	2014	627,604
5				
6				
7	Items under $250,000			30,592
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	None to Report			
23				
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47	Total			7,436,551

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	04/11/2013	2012/Q4

FOOTNOTE DATA

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	04/11/2013	End of 2012/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	Forestry KP D Base R W	2,612,829
2	KP/VoltVar Circ Reconfig DLine	1,419,487
3	KP/KY Volt/VAR Opt D-Line	2,653,256
4	TS/KY/ Replace & Refurbish	2,108,153
5	DS/KYPCO/Replace &Refurbish	1,130,148
6	TS/KyP/Bonnyman Sta removal	1,682,044
7	DS/KYPCO/Beckham 138kV Cntl Ho	1,347,537
8	T/KY/Line: Conxt: Bonnyman-Sof	12,531,340
9	WS-CI-KEPCo-G PPB	1,949,033
10	ET-CI-KEPCo-T ASSET IMP	1,246,867
11	Ed-Cl-Kepco-D Ast Imp	2,649,422
12	Other Minor Projects Under $1,000,000	12,951,176
13		
14		
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43	TOTAL	44,281,292

Name of Respondent Kentucky Power Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2013	Year/Period of Report 2012/Q4

FOOTNOTE DATA

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 (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2013	End of 2012/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	580,174,789	580,174,789		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	51,083,564	51,083,564		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	192,541	192,541		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	51,276,105	51,276,105		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	20,044,776	20,044,776		
13	Cost of Removal	11,939,202	11,939,202		
14	Salvage (Credit)	2,288,195	2,288,195		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	29,695,783	29,695,783		
16	Other Debit or Cr. Items (Describe, details in footnote):	-515,370	-515,370		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	601,239,741	601,239,741		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	267,211,806	267,211,806		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production				
25	Transmission	154,839,705	154,839,705		
26	Distribution	171,225,681	171,225,681		
27	Regional Transmission and Market Operation				
28	General	7,962,549	7,962,549		
29	TOTAL (Enter Total of lines 20 thru 28)	601,239,741	601,239,741		

Name of Respondent Kentucky Power Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2013	Year/Period of Report 2012/Q4

FOOTNOTE DATA

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

Asbestos ARO depreciation expense in account 1080013	$195,254
Adjustment for Bell Howell Inserter depreciation expense billed by AEPSC	-2,713
TOTAL	$192,541

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

Includes $4,608,459 of removal cost in retirement work in progress (RWIP).

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

Includes ($230,045) of salvage charges in retirement work in progress (RWIP).

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

Reserve for asbestos ARO in account 1080013 $-515,370

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	04/11/2013	End of 2012/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)
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42	Total Cost of Account 123.1 $ 0		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	04/11/2013	End of 2012/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
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Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2013	Year/Period of Report End of 2012/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)	22,597,653	67,280,320	
2	Fuel Stock Expenses Undistributed (Account 152)	408,137	1,866,856	
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	2,243,136	4,066,629	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	10,499,931	8,496,249	Electric
8	Transmission Plant (Estimated)	197,787	29,645	Electric
9	Distribution Plant (Estimated)	156,943	309,165	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	26,958	6,628	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	13,124,755	12,908,316	
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)	36,130,545	82,055,492	

Name of Respondent Kentucky Power Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2013	Year/Period of Report 2012/Q4

FOOTNOTE DATA

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

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

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	04/11/2013	End of 2012/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)	2013 No. (d)	2013 Amt. (e)
1	Balance-Beginning of Year	107,494.00	13,868,673	40,573.00	1,164,696
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Appalachian Power Company	1,670.00	1,062,186		
10	Ohio Power Company	19,019.00	5,033,939		
11					
12					
13					
14					
15	Total	20,689.00	6,096,125		
16					
17	Relinquished During Year:				
18	Charges to Account 509	43,923.00	8,796,259		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	AEP System Pool	1,744.00	208,544		
23					
24					
25					
26					
27					
28	Total	1,744.00	208,544		
29	Balance-End of Year	82,516.00	10,959,995	40,573.00	1,164,696
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	646.00		505.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	646.00			
40	Balance-End of Year			505.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)		340		
44	Net Sales Proceeds (Other)		340		
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	04/11/2013	End of 2012/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.

2014 No. (f)	2014 Amt. (g)	2015 No. (h)	2015 Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)	Line No.
46,563.00	2,361,231	34,754.00		904,195.00		1,133,579.00	17,394,600	1
								2
								3
				34,945.00		34,945.00		4
								5
								6
								7
								8
						1,670.00	1,062,186	9
						19,019.00	5,033,939	10
								11
								12
								13
								14
						20,689.00	6,096,125	15
								16
								17
						43,923.00	8,796,259	18
								19
								20
								21
						1,744.00	208,544	22
								23
								24
								25
								26
								27
						1,744.00	208,544	28
46,563.00	2,361,231	34,754.00		939,140.00		1,143,546.00	14,485,922	29
								30
								31
								32
								33
								34
								35
362.00		362.00		24,244.00		26,119.00		36
				723.00		723.00		37
								38
				361.00		1,007.00		39
362.00		362.00		24,606.00		25,835.00		40
								41
								42
								43
					65		405	44
					65		405	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	04/11/2013	End of 2012/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)	2013 No. (d)	2013 Amt. (e)
1	Balance-Beginning of Year	11,059.00	158,406	10,610.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	280.00			
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Accrued Purchase Reversal	-1,351.00	-119,884		
10	NRG Power Marketing LLC	225.00	11,813		
11	Seminole Electric Co-op	500.00	33,750		
12	Virginia Elec & Power Co.	410.00	21,525		
13					
14					
15	Total	-216.00	-52,796		
16					
17	Relinquished During Year:				
18	Charges to Account 509	7,693.00	77,336	375.00	
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Arkansas Electric Co-op	554.00			
23					
24					
25					
26					
27					
28	Total	554.00			
29	Balance-End of Year	2,876.00	28,274	10,235.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)		14,958		
33	Net Sales Proceeds (Other)				
34	Gains				
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	04/11/2013	End of 2012/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.

2014		2015		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
						32,279.00	158,406	1
10,610.00								2
								3
						280.00		4
								5
								6
								7
								8
						-1,351.00	-119,884	9
						225.00	11,813	10
						500.00	33,750	11
						410.00	21,525	12
								13
								14
						-216.00	-52,796	15
								16
								17
						8,068.00	77,336	18
								19
								20
								21
						554.00		22
								23
								24
								25
								26
								27
						554.00		28
						23,721.00	28,274	29
10,610.00								30
								31
								32
							14,958	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	04/11/2013	End of 2012/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 Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
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) 04/11/2013	Year/Period of Report End of 2012/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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2013	End of 2012/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					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	Generation Studies				
22					
23					
24					
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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	04/11/2013	End of 2012/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	18,444,554		593	4,698,444	11,746,110
2	Kentucky PSC Case No. 2009-00352					
3	Amortz period: July 2010 - June 2015					
4						
5	Deferred Storm Expenses - 2012		12,146,000			12,146,000
6						
7	SFAS 109 Deferred FIT	82,588,902	14,957,869	Various	11,235,739	86,311,032
8						
9	SFAS 109 Deferred SIT	41,595,141	2,343,790	Various	1,594,240	42,344,691
10						
11	Post In-Service AFUDC Hanging Rock/	699,048		406	33,408	665,640
12	Jefferson 765 KV Line					
13	Amortz period: Dec 1984 - Nov 2032					
14						
15	Depreciation Expense - Hanging Rock/	108,937		406	5,208	103,729
16	Jefferson 765 KV Line					
17	Amortz period: Dec 1984 - Nov 2032					
18						
19	Deferred DSM Expense	159,972	4,370,687	456, 908	2,941,336	1,589,323
20						
21	Deferred Carbon Management Research	225,006	250,000	188, 506	299,996	175,010
22	Kentucky PSC Case 2008-00308 & 2009-00459					
23	Amortz period: July 2010 - June 2018					
24						
25	Deferred Equity Carrying Charge	(130,113)	22,428			-107,685
26						
27	BridgeCo Transmission Org Funding	290,712		407,421	25,709	265,003
28	Amortz period: Jan 2005 - Dec 2019					
29	FERC Docket AC04-101-000					
30						
31	PJM Integration Payments	396,530		407, 421	122,527	274,003
32	Amortz period: Jan 2005 - Dec 2014					
33	FERC Docket EL05-74-000					
34						
35	Other PJM Integration	307,137		407, 421	27,161	279,976
36	Amortz period: Jan 2005 - Dec 2019					
37	FERC Docket AC04-101-000					
38						
39	Carrying Charges - RTO Startup Costs	177,149	93,870	407, 421	122,662	148,357
40	Amortz period: Jan 2005 - Dec 2019					
41	FERC Docket AC04-101-000					
42						
43						
44	TOTAL	215,517,254	414,305,055	[illegible]	415,591,647	214,230,662

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	04/11/2013	End of 2012/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	Alliance RTO Deferred Expense	152,156		407, 421	13,456	138,700
2	Amortz period: Jan 2005 - Dec 2019					
3	FERC Docket AC04-101-000					
4						
5	SFAS 112 Post Employment Benefit	5,204,957	309,526	Various	284,770	5,229,713
6						
7	SFAS 158 Employers' Accounting for Defined	66,392,038	99,960,537	Various	114,304,374	52,048,201
8	Benefit Pension and Other Postretirement Plans					
9						
10	Unrealized Loss on Forward Commitments		279,846,423	Various	279,846,423	
11						
12	Carbon Capture FEED Study	905,128	3,925	146	38,194	872,859
13						
14						
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41						
42						
43						
44	TOTAL	215,517,254	414,305,055		415,591,647	214,230,662

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2013	Year/Period of Report End of 2012/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	10,031,245	10,424,709	408	10,031,245	10,424,709
2						
3	Liquidated Rail Damages	4,180,000	2,750,000	232, 253	4,180,000	2,750,000
4						
5	Agency Fees - Factored A/R	1,035,850	10,600,477	Various	10,725,808	910,519
6						
7	Unamortized Credit Line Fees	719,096	56,709	431	233,655	542,150
8	Amortized thru July 2016					
9						
10	Deferred Lease Assets	20,834	601,450	Various	420,601	201,683
11						
12	Miscellaneous Items	-1,510	164,658	Various	162,666	482
13						
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15						
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46						
47	Misc. Work in Progress	63,901				184,204
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	16,049,416				15,013,747

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2013	Year/Period of Report End of 2012/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	6,075,432	6,454,725
2	Interest Expense Capitalized	2,627,149	2,181,725
3	Contribution-In-Aid Of Construction	4,175,150	7,110,307
4	Deferred Fuel	-7,471,544	-7,867,069
5	Pension	3,421,136	3,199,428
6	SFAS 106 Post Retirement Expenses	11,133,246	2,640,297
7	Other	19,960,569	13,719,413
8	TOTAL Electric (Enter Total of lines 2 thru 7)		
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15	14,422,110	14,660,289
17	Other (Specify)	34,382,679	28,379,702
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)		

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	04/11/2013	2012/Q4

FOOTNOTE DATA

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

Page 234 Line 17	Beginning of Year	End of Year
Non-Utility - Acct 190.2	640,632	753,067
SFAS 109	13,412,870	13,663,909
SFAS 133	368,608	243,313
	14,422,110	14,660,289

Summary:

1901001	Accum DFIT - Other	13,719,413
1902001	Accum DFIT - Other Income & Deductions	753,067
1903001	Accum DFIT - SFAS 109 Flow-Thru	13,322,568
1904001	Accum DFIT - SFAS 109 Excess	341,341
	SubTotal A/C 190	28,136,389
1900006	SFAS 133 Non-Affil Fed Accum DFIT	91,485
1900015	ADIT-Fed-Hdg-CF-Int Rate	151,828
	TOTAL A/C 190	28,379,702

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	04/11/2013	End of 2012/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				
4				
5				
6				
7				
8				
9				
10				
11				
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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	04/11/2013	End of 2012/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
1,009,000	50,450,000					2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
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						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	04/11/2013	End of 2012/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	238,750,000
2	Contributions by Parent Company prior to 2011	
3		238,750,000
4	Subtotal - Account 208	
5		
6	Account 209 - Reduction In Par or Stated Value of Capital Stock	
7		
8	Account 210 - Gain on Resale/Cancellation of Reacquired Capital Stock	
9		
10	Account 211 - Miscellaneous Paid-In-Capital	
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37		
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39		
40	TOTAL	238,750,000

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	04/11/2013	End of 2012/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	04/11/2013	End of 2012/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	None		
3	SUBTOTAL ACCOUNT 221 - BONDS		
4			
5	ACCOUNT 222 - REQUIRED BONDS		
6	None		
7	SUBTOTAL ACCOUNT 222 - REQUIRED BONDS		
8			
9	ACCOUNT 223 - ADVANCES FROM ASSOCIATED COMPANIES	20,000,000	
10	Note Payable to Parent Company (American Electric Power Company) - 5.250%	20,000,000	
11	SUBTOTAL ACCOUNT 223 - ADVANCES FROM ASSOCIATED COMPANIES		
12			
13	ACCOUNT 224 - OTHER LONG-TERM DEBT	75,000,000	736,575
14	Senior Unsecured Notes - 5.625%, Series D		
15		325,000,000	2,277,883
16	Senior Unsecured Notes - 6.000%, Series E		1,667,250 D
17	KPSC Authority Docket No.2006-0034		
18			
19	Amortization of Cash Flow Hedges on 6.000% SUN		
20		40,000,000	217,919
21	Senior Unsecured Notes - 7.250%, State Commission Authority Case # 2008-00442		
22		30,000,000	148,032
23	Senior Unsecured Notes - 8.030%, State Commission Authority Case # 2008-00442		
24		60,000,000	342,285
25	Senior Unsecured Notes - 8.130%, State Commission Authority Case # 2008-00442		
26			
27			
28			
29			
30		530,000,000	5,389,944
31	SUBTOTAL ACCOUNT 224 - OTHER LONG-TERM DEBT		
32			
33	TOTAL	550,000,000	5,389,944

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	04/11/2013	End of 2012/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
02/05/2004	06/01/2015			20,000,000	1,050,000	10
				20,000,000	1,050,000	11
						12
						13
06/13/2003	12/01/2032	06/13/2003	12/01/2032	75,000,000	4,218,750	14
						15
09/11/2007	09/15/2017	09/11/2007	09/15/2017	325,000,000	19,500,000	16
						17
						18
		09/11/2007	09/15/2017		92,956	19
						20
06/18/2009	06/18/2021	06/18/2009	06/18/2021	40,000,000	2,900,000	21
						22
06/18/2009	06/18/2029	06/18/2009	06/18/2029	30,000,000	2,409,000	23
						24
06/18/2009	06/18/2039	06/18/2009	06/18/2039	60,000,000	4,878,000	25
						26
						27
						28
						29
						30
				530,000,000	33,998,706	31
						32
				550,000,000	35,048,706	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	04/11/2013	2012/Q4

FOOTNOTE DATA

Schedule Page: 256 Line No.: 26 Column: i

The difference between the total interest on this schedule and the total of account 427 and 430 is due to interest on short-term advances from the AEP Money Pool.

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	04/11/2013	End of 2012/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)	50,978,453
2		[redacted]
3		[redacted]
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		[redacted]
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13		[redacted]
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		[redacted]
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25		
26		29,307,039
27	Federal Tax Net Income	
28	Show Computation of Tax:	
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	04/11/2013	2012/Q4

FOOTNOTE DATA

Schedule Page: 261 Line No.: 26 Column: b

	In (000's)
Net Income for the year per Page 117, Line 78	50,978
Federal Income Taxes	20,070
State Income Taxes	2,332
Pretax Book Income	73,380
Increase (Decrease) in Taxable Income resulting from:	
Allowance for Funds Used During Construction and Other Differences between Items Capitalized for Books and Expensed for Tax	(568)
Capitalized Relocation Costs	0
Deferred Fuel Cost (Net)	4,790
Deferred Storm Damage	(7,448)
Demand Side Management (Net)	(1,429)
Emission Allowances (Net)	2,128
Excess Tax Vs. Book Depreciation	(32,680)
Mark-to-Market	(112)
Pension Expenses (Net)	(1,240)
RTO Expenses and Carrying Charges	190
Removal Costs - ACRS	(11,101)
Repair Allowance	0
Book Unit of Property Adjustment	(100)
Self Insurance - Book Reserve	(762)
SFAS 106 - Post Retirement Benefit Expense Accrued/Funded (Net)	(597)
Medicare subsidy	414
Tax Accruals and Deferrals	(107)
Pollution Control Equipment	4,500
Accrd Book ARO Exp	(376)
Misc Book Accruals and Deferrals	979
Provision for Possible Revenue Refunds	2,030
Sales & Use Tax Reserves	0
Accrued Tax Reserve - FIN 48	(175)
Accrued Interest - Long & Short Term	(49)
Mitigation Programs - Federal & State	(371)
Non-Deductible Fines & Penalties	0
Other (Net)	645

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) 04/11/2013	2012/Q4

FOOTNOTE DATA

Federal Taxable Income before State Income Taxes		31,941
State Income Taxes		2,634
Federal Taxable Net Income - Estimated Current Year Taxable Income (Separate Return Basis)		29,307
Computation of Tax		
Federal Income Tax on Current Year Taxable Income (Separate Return Basis) at the Statutory Rate of 35%		10,257
Adjustment due to System Consolidation	(a)	(1,292)
Tax Provision Adjustment		0
Audit Settlement		0
R&D Credit		0
Estimated Tax Currently Payable	(b)	8,965
Adjustments of Prior Year's Accruals (Net)		1,303
Estimated Current Federal Income Taxes (Net)		10,268

(a) Represents the allocation of 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 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, Inc., is allocated to its subsidiaries with taxable income. With the exception of the loss 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 2012 system Federal income taxes will not be available until the consolidated Federal income tax return is completed and filed by September 2013. 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 tax return is filed.

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2013	Year/Period of Report End of 2012/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	5,515,783		10,268,313	19,943,967	-929,530
3	INCOME TAX - IRS Audit					14,832
4	FICA - 2012	290,844		2,764,619	2,697,886	
5	Unemployment - 2012	13,903		30,504	26,801	
6						
7	Federal Excise Tax - 2012			998	998	
8						
9	STATE INC. TAX - FIN 48	168,273		-175,465		
10						
11	STATE OF ILLINOIS:					
12	Income 2011	34,385		-39,690	-5,305	
13	2012			106,826	72,905	
14						
15	STATE OF KENTUCKY:					
16	Income 2011	649,918		-229,630	420,288	
17	2012			3,197,198	3,155,712	
18						
19	License Fee 2012: Muni			300	300	
20	State			15	15	
21						
22						
23	Unemployment - KY 2012	6,137		31,286	37,150	
24						
25	PUBLIC SER COMM'S-2011		412,861	412,861		
26	PUBLIC SER COMM'S-2012			515,095	1,030,190	
27	USE TAX - 2011	119,166	51,118	28,027	96,075	
28	USE TAX - 2012			1,274,657	1,065,907	
29	SALES TAX - 2011		348,741		-348,741	
30	SALES TAX - 2012				294,773	
31	REAL & PERS PROP-2008	447		-447		
32	REAL & PERS PROP-2009	31,715		-30,160	1,555	
33	REAL & PERS PROP-2010	2,365,729		-98,374	2,170,618	
34	REAL & PERS PROP-2011	10,031,245			9,500,787	
35	REAL & PERS PROP-2012			10,424,709		
36	PERS PROP LEASED-2009	-18		18		
37	PERS PROP LEASED-2010	104,116		-104,116		
38	PERS PROP LEASED-2011	77,648		-62,800	4,580	
39	PERS PROP LEASED-2012			16,699	12,326	
40	REAL PROP LEASED-2008					
41	TOTAL	19,319,996	812,720	28,000,643	39,897,091	-914,698

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	04/11/2013	End of 2012/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 PROP LEASED-2009	-311		311		
2	REAL PROP LEASES-2011	-2,190		2,257	67	
3	REAL PROP LEASES-2012			26,745	26,745	
4						
5	STATE OF WEST VIRGINIA:					
6	Income 2009	-63,670				
7	2011	-19,707		-42,501	-62,208	
8	2012				49,500	
9	Franchise - 2011	-8,908		-22,194	-31,102	
10	2012			10,345	38,300	
11						
12	USE - 2011	1,779		-977	802	
13	USE - 2012			1,996	852	
14						
15	PERS PROP LEASED-2010			2,063	2,063	
16	PERS PROP LEASED-2011			978	978	
17						
18	WV License Fee - 2012			25	25	
19						
20	WV State Unemployment -	106		974	1,080	
21	OK State License Fee 2012					
22	Michigan License Fee 2011					
23	Tennessee License Fee 2011					
24	Utah License Fee 2011					
25	Wyoming License Fee 2011					
26						
27	STATE OF OHIO:					
28	Income - 2000			-498,211	-498,211	
29						
30	OH CAT TAX - 2011	48,000		30,112	78,112	
31	OH CAT TAX - 2012			144,101	111,101	
32						
33	STATE OF MICHIGAN:					
34	Income 2011	-44,394		9,326	-35,068	
35	2012			3,850	35,068	
36						
37	OTHER:					
38	REAL/PERS PROP-LA-2012				200	
39	PA License Fee - 2009					
40						
41	TOTAL	19,319,996	812,720	28,000,643	39,897,091	-914,698

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	04/11/2013	End of 2012/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
					-757,316	2
-5,089,401		11,025,629				3
14,832					1,104,592	4
357,577		1,660,027			8,162	5
17,606		22,342				6
						7
		998				8
						9
-7,192		-175,465				10
						11
					-708	12
		-38,982			696	13
33,921		106,130				14
						15
					-5,017	16
		-224,613			22,222	17
41,486		3,174,976				18
						19
		300				20
		15				21
						22
					14,200	23
274		17,086				24
						25
		412,861				26
	515,095	515,095			26,780	27
		1,247			1,264,852	28
251,468	42,719	9,805				29
						30
	294,773					31
		-447				32
		-30,160				33
96,737		-98,374			-9,603,943	34
530,458		9,603,943			10,424,709	35
10,424,707						36
		18				37
		-104,116				38
10,268		-62,800				39
4,373		16,699			-311	40
		311				
6,548,715	852,587	25,501,516			2,499,127	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	04/11/2013	End of 2012/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 (Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	DISTRIBUTION OF TAXES CHARGED Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	Line No.
					311	1
		2,257				2
		26,745				3
						4
						5
-63,670						6
		-41,545			-956	7
-49,500						8
		-22,194				9
-27,955		10,345				10
						11
					-977	12
1,144					1,996	13
						14
		2,063				15
		978				16
						17
		50			-25	18
						19
		564			410	20
		100			-100	21
						22
						23
						24
						25
						26
						27
		-498,211				28
						29
		30,112				30
33,000		144,101				31
						32
						33
		9,802			-476	34
-31,218		3,824			26	35
						36
						37
-200						38
						39
						40
6,548,715	852,587	25,501,516			2,499,127	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	04/11/2013	2012/Q4

FOOTNOTE DATA

Schedule Page: 262 Line No.: 2 Column: f
Consists primarily of Tax Credit Carryforward

Schedule Page: 262 Line No.: 3 Column: f
Consists of recorded federal income tax as a result of IRS Audit

Schedule Page: 262 Line No.: 29 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.: 30 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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2013	End of 2012/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: Account No. (c)	Deferred for Year: Amount (d)	Allocations to Current Year's Income: Account No. (e)	Allocations to Current Year's Income: Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	633,764			411.4	278,005	
6							
7						278,005	
8	TOTAL	633,764					
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
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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	04/11/2013	End of 2012/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
			5
355,759			6
			7
			8
355,759			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
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			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	04/11/2013	2012/Q4

FOOTNOTE DATA

Schedule Page: 266 Line No.: 5 Column: i

Remaining amortization period is 8 years.

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	04/11/2013	End of 2012/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	153,385	454	624,714	550,269	78,940
2						
3	Customer Advance Receipts	1,901,792	142, 143	24,950,382	25,683,088	2,634,498
4						
5	Deferred Gain:	167,611	124	4,997		162,614
6	Fiber Optic Agrmts-In Kind Svc					
7	Amortize through June 2026					
8						
9	Deferred Revenue	130,285	451	13,556		116,729
10	Fiber Optic Lines-Sold-Defd Rev					
11	Amortize through January 2025					
12						
13	IPP - System Upgrade Credits	251,989			8,290	260,279
14						
15	Miscellaneous	4,416	143	4,416	6,461	6,461
16						
17	Federal Mitigation Deferral (NSR)				754,942	754,942
18						
19	Contract Settlement Reserve	987,973				987,973
20						
21	Liquidated Rail Damages	2,750,000	186	2,750,000		
22						
23	Fiber Optic Annual Maintenance				118,893	118,893
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	6,347,451		28,348,065	27,121,943	5,121,329

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	04/11/2013	End of 2012/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	28,229,670		1,585,032
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	28,229,670		1,585,032
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)	28,229,670		1,585,032
18	Classification of TOTAL			
19	Federal Income Tax	28,229,670		1,585,032
20	State Income Tax			
21	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	04/11/2013	End of 2012/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		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)	(k)	
							1
							2
							3
						26,644,638	4
							5
							6
							7
						26,644,638	8
							9
							10
							11
							12
							13
							14
							15
							16
						26,644,638	17
							18
						26,644,638	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	04/11/2013	End of 2012/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 (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 282			
2	Electric	191,985,551	22,140,295	15,402,729
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	191,985,551	22,140,295	15,402,729
6	SFAS 109	51,175,825		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	243,161,376	22,140,295	15,402,729
10	Classification of TOTAL			
11	Federal Income Tax	243,161,376	22,140,295	15,402,729
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	04/11/2013	End of 2012/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		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)	(k)	
							1
						198,723,117	2
							3
							4
						198,723,117	5
				1823/254	2,602,791	53,778,616	6
							7
							8
					2,602,791	252,501,733	9
							10
					2,602,791	252,501,733	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	04/11/2013	End of 2012/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)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Deferred Fuel Costs	3,076,868	3,039,811	1,781,286
4	Mark to Market	3,618,492	3,220,268	3,339,611
5	Capitalized Software - Book	1,796,218	91,030	76,187
6	SFAS 158	6,994,693	269	5,455,589
7	Reg Asset - SFAS 112	1,821,734	108,335	99,669
8	Other	1,520,524	9,241,908	5,244,206
9	TOTAL Electric (Total of lines 3 thru 8)	18,828,529	15,701,621	15,996,548
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other	85,159,433		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	103,987,962	15,701,621	15,996,548
20	Classification of TOTAL			
21	Federal Income Tax	62,392,821	15,701,621	15,996,548
22	State Income Tax	41,595,141		
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	04/11/2013	End of 2012/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				Balance at End of Year	Line No.
		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)	(k)	
							1
							2
						4,335,393	3
						3,499,149	4
						1,811,061	5
						1,539,373	6
						1,830,400	7
						5,518,226	8
						18,533,602	9
							10
							11
							12
							13
							14
							15
							16
							17
8,327	415	Various	6,093,523	Various	8,399,371	87,473,193	18
8,327	415		6,093,523		8,399,371	106,006,795	19
							20
8,327	415	Various	4,499,283	Various	6,055,581	63,662,104	21
			1,594,240	283.3	2,343,790	42,344,691	22
							23

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	04/11/2013	2012/Q4

FOOTNOTE DATA

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

	Beginning Balance	Ending Balance
Other:		
Mark to Market	-477	0
Emissions	113,957	113,542
Reg Asset - Deferred Equity Carrying Charges	-45,539	-37,689
SFAS 109	85,059,556	87,374,194
SFAS 133	31,936	23,146
	85,159,433	87,473,193

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	04/11/2013	End of 2012/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 (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Home Energy Assistance Program	266,401	Various	498,821	465,909	233,489
2						
3	SFAS 109 Deferred FIT	1,361,533	Various	214,903	20,191	1,166,821
4						
5	Unrealized Gain on Forward Commitments	3,536,245	Various	332,929,789	333,681,099	4,287,555
6						
7	Green Pricing Option	614				614
8						
9	Over Recovered Fuel Cost	3,137,946	182.3	62,167,454	66,977,831	7,928,323
10						
11	Kentucky Enhanced Reliability		593	1,470,904	1,666,068	215,164
12						
13						
14						
15						
16						
17						
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36						
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38						
39						
40						
41	TOTAL	8,302,739	[illegible]	397,301,871	402,831,098	13,831,966

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	04/11/2013	End of 2012/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	205,798,905	226,169,378
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	125,717,218	135,517,406
5	Large (or Ind.) (See Instr. 4)	167,974,954	195,863,609
6	(444) Public Street and Highway Lighting	1,545,674	1,618,697
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	501,036,751	559,169,090
11	(447) Sales for Resale	100,941,442	155,806,427
12	TOTAL Sales of Electricity	601,978,193	714,975,517
13	(Less) (449.1) Provision for Rate Refunds	1,635,430	
14	TOTAL Revenues Net of Prov. for Refunds	600,342,763	714,975,517
15	Other Operating Revenues		
16	(450) Forfeited Discounts	3,268,233	2,221,319
17	(451) Miscellaneous Service Revenues	353,912	432,634
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	7,006,537	5,246,624
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	3,289,883	3,648,114
22	(456.1) Revenues from Transmission of Electricity of Others	17,193,946	14,477,016
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	31,112,511	26,025,707
27	TOTAL Electric Operating Revenues	631,455,274	741,001,224

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Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2013	End of 2012/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)	
				1
2,240,727	2,342,021	140,929	141,860	2
				3
1,349,653	1,380,707	30,059	29,964	4
3,059,752	3,249,891	1,368	1,406	5
10,524	10,544	401	411	6
				7
				8
				9
6,660,656	6,983,163	172,757	173,641	10
2,936,231	4,152,046	102	115	11
9,596,887	11,135,209	172,859	173,756	12
				13
9,596,887	11,135,209	172,859	173,756	14

Line 12, column (b) includes $ -1,817,619 of unbilled revenues.
Line 12, column (d) includes 6,051 MWH relating to unbilled revenues

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	04/11/2013	2012/Q4

FOOTNOTE DATA

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

Detail of Unmetered Sales:

	Revenue	MWH	Average Customers
Residential	5,010,876	26,797	40,260
Commercial	2,250,797	15,320	7,170
Industrial	123,674	928	256
Public Street Lighting	22,249	106	36
Total	7,407,596	43,151	47,722

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

Customer Service Revenues (1)	$	340,256
All other under $25,000 each		13,656
	$	353,912

(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 Elect Rev - Demand Side Management Program	$ 3,101,792
All Other (under $250,000)	188,091
	$ 3,289,883

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	04/11/2013	End of 2012/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					
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33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2013	Year/Period of Report End of 2012/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	2,197,557	200,713,978	140,824	15,605	0.0913
3	Res Service Load Management	2,515	200,766	100	25,150	0.0798
4	Residential Service TOD	43	3,715	3	14,333	0.0864
5	Small General Service	15	1,817	2	7,500	0.1211
6	All Outdoor Lighting	26,797	5,010,876			0.1870
7	Subtotal Billed	2,226,927	205,931,152	140,929	15,802	0.0925
8	Unbilled Revenue	13,800	-132,247			-0.0096
9	Total Residential	2,240,727	205,798,905	140,929	15,900	0.0918
10						
11	442 Commercial Sales					
12	Small General Service	128,823	15,790,067	22,292	5,779	0.1226
13	Medium General Service	473,288	48,346,041	6,942	68,177	0.1021
14	Medium General Service TOD	4,015	360,465	79	50,823	0.0898
15	Large General Service	549,481	48,690,306	711	772,828	0.0886
16	Quantity Power	171,687	10,364,349	21	8,175,571	0.0604
17	All Outdoor Lighting	15,320	2,250,797			0.1469
18	Mark West HC	4,415	367,687	13	339,615	0.0833
19	Estimated Revenue	495	36,596	1	495,000	0.0739
20	Subtotal Billed	1,347,524	126,206,308	30,059	44,829	0.0937
21	Unbilled Revenue	2,129	-489,092			-0.2297
22	Total Commercial	1,349,653	125,717,216	30,059	44,900	0.0931
23						
24	442 Industrial Sales					
25	Small General Service	5,192	598,435	777	6,682	0.1153
26	Medium General Service	28,124	2,842,209	346	81,283	0.1011
27	Large General Service	158,479	13,558,445	166	954,693	0.0856
28	Quantity Power	571,034	39,378,033	63	9,064,032	0.0690
29	Commercial & Industrial TOD	2,172,053	107,395,388	16	135,753,313	0.0494
30	All Outdoor Lighting	928	123,674			0.1333
31	Estimated Revenue	133,820	5,273,380			0.0394
32	Subtotal Billed	3,069,630	169,169,564	1,368	2,243,882	0.0551
33	Unbilled Revenue	-9,878	-1,194,610			0.1209
34	Total Industrial	3,059,752	167,974,954	1,368	2,236,661	0.0549
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	6,654,605	502,854,370	172,757	38,520	0.0756
42	Total Unbilled Rev.(See Instr. 6)	6,051	-1,817,619	0	0	-0.3004
43	TOTAL	6,660,656	501,036,751	172,757	38,555	0.0752

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	04/11/2013	End of 2012/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	444 Public Street Lighting					
2	Small General Service	723	123,097	334	2,165	0.1703
3	Medium General Service	1,208	118,506	11	109,818	0.0981
4	Street Lighting	8,487	1,283,492	56	151,554	0.1512
5	All Outdoor Lighting	106	22,249			0.2099
6	Subtotal Billed	10,524	1,547,344	401	26,244	0.1470
7	Unbilled Revenue		-1,670			
8	Total Public Street Lighting	10,524	1,545,674	401	26,244	0.1469
9						
10	Instruction 5. (See Footnote)					
11						
12						
13						
14						
15						
16						
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22						
23						
24						
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26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	6,654,605	502,854,370	172,757	38,520	0.0756
42	Total Unbilled Rev.(See Instr. 6)	6,051	-1,817,619	0	0	-0.3004
43	TOTAL	6,660,656	501,036,751	172,757	38,555	0.0752

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	04/11/2013	2012/Q4

FOOTNOTE DATA

Schedule Page: 304.1 Line No.: 10 Column: a

FUEL CLAUSE

440 Residential	
Residential Service	1,478,499
Res Service Load Management	1,568
Residential Service TOD	22
All Outdoor Lighting	15,643
Small General Service	(7)
Unbilled	960,294
Total Residential	2,456,019
442 Commercial	
Mark West HC	3,961
Small General Service	94,427
Medium General Service	369,410
Medium General Service TOD	3,119
Large General Service	441,685
Quantity Power	129,809
All Outdoor Lighting	8,870
Estimated	10,488
Unbilled	482,272
Total Commercial	1,544,041
442 Industrial	
Small General Service	3,666
Medium General Service	16,660
Large General Service	124,619
Quantity Power	603,955
Commercial & Industrial TOD	2,538,234
All Outdoor Lighting	544
Estimated	5,235
Unbilled	429,076
Total Industrial	3,721,989
444 Public Street Lighting	
Small General Service	548
Medium General Service	911
Street Lighting	4,915
All Outdoor Lighting	60
Unbilled	984
Total Public Street Light	7,418
TOTAL FUEL CLAUSE	7,729,467

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	04/11/2013	End of 2012/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 long-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.
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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.
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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	PJM Transmission for RQ Customers	RQ	Various			
2	City of Olive Hill	RQ	KPCO 52			
3	City of Vanceburg	RQ	KPCO 51			
4	AEP Service Corporation	OS	11			
5	AEP Service Corporation	OS	20			
6	Adjustment	OS	See footnote			
7	Advan Promotions Inc.	OS	Note 1			
8	Allegheny Electric Cooperative	OS	Note 1			
9	AmerenCILCO, CIPS, Ameren IP	OS	Note 1			
10	Ameren Energy Marketing	OS	Note 1			
11	American Municipal Power - Ohio	OS	Note 1			
12	Associated Electric Cooperative	OS	Note 1			
13	American PowerNet Management	OS	Note 1			
14	J ARON & Company	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2013	Year/Period of Report End of 2012/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).
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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.
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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	Barclays Bank PLC	OS	Note 1			
2	Beech Ridge Energy LLC	OS	Note 1			
3	Town of Berlin, Maryland	OS	Note 1			
4	Village of Bethel, Ohio	OS	Note 1			
5	BP AMOCO	OS	Note 1			
6	BP Energy Company	OS	Note 1			
7	The Borough of Pitcalrn, PA	OS	Note 1			
8	Big Rivers Electric Corporation	OS	Note 1			
9	Buckeye Rural Electric Administration	OS	Note 1			
10	Calpine Power Service Company	OS	Note 1			
11	Constellation Energy Commodities	OS	Note 1			
12	City of Dowagiac, MI	OS	Note 1			
13	Commonwealth Edison Company	OS	Note 1			
14	Citigroup Energy 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	04/11/2013	End of 2012/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).
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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	Cook Inlet Energy Supply LP	OS	Note 1			
2	Citizens Electric Co & Wellsborough	OS	Note 1			
3	Cleveland Toledo OH PA Electric	OS	Note 1			
4	City of Columbus	OS	Note 1			
5	Conoco Inc.	OS	Note 1			
6	Carolina Power & Light	OS	Note 1			
7	Cleveland Public Power	OS	Note 1			
8	California Power Exchange	OS	Note 1			
9	City of Croswell, MI	OS	Note 1			
10	DB Energy Trading LLC	OS	Note 1			
11	Dominion Equipment Inc.	OS	Note 1			
12	Duke Energy Ohio, Inc.	OS	Note 1			
13	Delaware Electric Municipal Co	OS	Note 1			
14	Dairyland Power Cooperative	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	04/11/2013	End of 2012/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).
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1	DP&L Power Services	OS	Note 1			
2	DTE Energy Trading Inc.	OS	Note 1			
3	Duke Energy Carolinas, LLC	OS	Note 1			
4	Duke Energy Indiana, Inc.	OS	Note 1			
5	EDF Trading North America LLC	OS	Note 1			
6	East KY Power Co-Op Power Mktg	OS	See footnote			
7	Eng Mktg, div of Amerada Hess	OS	Note 1			
8	Edison Mission Mktg & Trading	OS	Note 1			
9	Energy America, LLC	OS	Note 1			
10	Endure Energy, LLC	OS	Note 1			
11	Entergy Power Service	OS	Note 1			
12	PP&L Energy Plus Co.	OS	Note 1			
13	Easton Utilities	OS	Note 1			
14	Exelon Generation - Power Team	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	04/11/2013	End of 2012/Q4

SALES FOR RESALE (Account 447)

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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	FirstEnergy Trading Services	OS	Note 1			
2	GBC Metals, LLC	OS	Note 1			
3	Village of Glouster	OS	Note 1			
4	Great River Energy	OS	Note 1			
5	Village of Hamersville, Ohio	OS	Note 1			
6	Hoosier Power Market	OS	Note 1			
7	Harrison Rural Electrification	OS	Note 1			
8	Integrys Energy Services, Inc.	OS	Note 1			
9	Illinois Municipal Power Agency	OS	Note 1			
10	Indiana Municipal Power Agency	OS	Note 1			
11	Interstate Gas Supply, Inc.	OS	Note 1			
12	Indianapolis Power & Light Co.	OS	Note 1			
13	Interstate Power & Light Co.	OS	Note 1			
14	JP Morgan Ventures Energy Corp.	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

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Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2013	End of 2012/Q4

SALES FOR RESALE (Account 447)

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1	Kansas City Power & Light Co.	OS	Note 1			
2	City of Kirkwood, Missouri	OS	Note 1			
3	Kentucky Municipal Power Agency	OS	Note 1			
4	LG&E Utilities Power Sales	OS	Note 1			
5	Letterkenny Industrial Dev Auth	OS	Note 1			
6	L&P Electric Inc.	OS	Note 1			
7	City of Batavia	OS	Note 1			
8	MidAmerican Energy	OS	Note 1			
9	City of Medford	OS	Note 1			
10	Midwest ISO	OS	Note 1			
11	ALLETE, Inc. dba Minnesota Power	OS	Note 1			
12	Michigan Public Power Agency	OS	Note 1			
13	Morgan Stanley Capt.	OS	Note 1			
14	Mizuho Securities USA 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
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1	Paribas	OS	Note 1			
2	Noble Americas Gas and Power Corp	OS	Note 1			
3	NC Electric Membership Corp.	OS	Note 1			
4	No Carolina Muni Pwr Agency #1	OS	Note 1			
5	NextEra Energy Power Mktg LLC	OS	Note 1			
6	NRG Power Marketing Inc.	OS	Note 1			
7	NSP Energy Marketing	OS	Note 1			
8	Old Dominion Elec.	OS	Note 1			
9	OPC Variable	OS	Note 1			
10	Otter Tail Power Company	OS	Note 1			
11	OVEC Power Scheduling	OS	Note 1			
12	Peco Energy Company	OS	Note 1			
13	Prairieland Energy Incorporate	OS	Note 1			
14	PEPCO Services 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	04/11/2013	End of 2012/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	Potomac Electric Power Company	OS	Note 1			
2	PJM Interconnection	OS	Note 1			
3	PJM Environmental Info Sys Inc.	OS	Note 1			
4	The Potomac Edison Company	OS	Note 1			
5	PPL Electric Utilities Corp.	OS	Note 1			
6	PSEG Energy Resources & Trade	OS	Note 1			
7	Union Power Partners	OS	Note 1			
8	Quasar Energy Power Marketing	OS	Note 1			
9	Village of Ripley, Ohio	OS	Note 1			
10	Village of Sebewaing, Michigan	OS	Note 1			
11	Shell Energy N America (US) LP	OS	Note 1			
12	Sempra Energy Solutions	OS	Note 1			
13	City of Shelby	OS	Note 1			
14	Southern Illinois Power Co-Op	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	04/11/2013	End of 2012/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 long-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	Southern Maryland Elec Co-Op Inc.	OS	Note 1			
2	Prairie Power, Inc.	OS	Note 1			
3	Southern Company	OS	Note 1			
4	The Energy Authority	OS	Note 1			
5	Timber Canyon	OS	Note 1			
6	Tenaska Power Services Company	OS	Note 1			
7	Town of Hagerstown, Indiana	OS	Note 1			
8	TVA Bulk Power Trading	OS	Note 1			
9	UBS AG, London Branch	OS	Note 1			
10	UBS Securities LLC	OS	Note 1			
11	Union Electric Company	OS	Note 1			
12	Virginia City Hybrid Energy Center	OS	Note 1			
13	Washington Gas Energy Services	OS	Note 1			
14	Wisconsin Power & Light	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2013	Year/Period of Report End of 2012/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 long-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 Classifi-cation (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	West Penn Power Company	OS	Note 1			
2	Wolverine Power Supply Co-Op	OS	Note 1			
3	Westar Energy Inc.	OS	Note 1			
4	City of Westerville	OS	Note 1			
5	Wabash Valley Power Assn Inc.	OS	Note 1			
6						
7						
8						
9						
10						
11						
12						
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	04/11/2013	End of 2012/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.
			-536,222	-536,222	1
24,761	832,410	973,595		1,806,005	2
69,397	2,147,947	2,433,158		4,581,105	3
1,230,410		32,512,794		32,512,794	4
2,475		72,830		72,830	5
		-256,487		-256,487	6
		-2,309		-2,309	7
29,552		1,609,286		1,609,286	8
1,071		44,662		44,662	9
-8,309		-343,625		-343,625	10
21,748	268,027	1,281,890		1,549,917	11
-479		-13,130		-13,130	12
4,854		199,887		199,887	13
170,405		4,899,412		4,899,412	14
94,158	2,980,357	3,406,753	-536,222	5,850,888	
2,842,073	1,877,839	93,212,715	0	95,090,554	
2,936,231	4,858,196	96,619,468	-536,222	100,941,442	

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	04/11/2013	End of 2012/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.
16,883		670,005		670,005	1
		-15,130		-15,130	2
2,565		162,399		162,399	3
1,699		87,973		87,973	4
		52,256		52,256	5
4,937		275,554		275,554	6
785		33,571		33,571	7
					8
14,705		6,579,822		6,579,822	9
-302		-7,333		-7,333	10
-590		-209,339		-209,339	11
		330		330	12
22,965		970,595		970,595	13
		19,870		19,870	14
94,158	2,980,357	3,406,753	-536,222	5,850,888	
2,842,073	1,877,839	93,212,715	0	95,090,554	
2,936,231	4,858,196	96,619,468	-536,222	100,941,442	

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	04/11/2013	End of 2012/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.
		30,493		30,493	1
635		33,475		33,475	2
	97,772	-122		97,650	3
52,995		3,512,021		3,512,021	4
		56,223		56,223	5
62		2,060		2,060	6
11,950		623,768		623,768	7
		299		299	8
2,527		122,392		122,392	9
29,448		1,094,731		1,094,731	10
2,153		85,276		85,276	11
22,051		1,097,327		1,097,327	12
11,159		725,357		725,357	13
125		16,866		16,866	14
94,158	2,980,357	3,406,753	-536,222	5,850,888	
2,842,073	1,877,839	93,212,715	0	95,090,554	
2,936,231	4,858,196	96,619,468	-536,222	100,941,442	

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	04/11/2013	End of 2012/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.
		-74,818		-74,818	1
	1,395	-3,691		-2,296	2
18		-345		-345	3
		116,901		116,901	4
43,216		2,147,628		2,147,628	5
26,658		1,023,706		1,023,706	6
		328,389		328,389	7
	41,324	7,019		48,343	8
		247,171		247,171	9
		-740		-740	10
-183		-8,669		-8,669	11
		-519,758		-519,758	12
3,199		173,594		173,594	13
-3,149		-3,021,072		-3,021,072	14
94,158	2,980,357	3,406,753	-536,222	5,850,888	
2,842,073	1,877,839	93,212,715	0	95,090,554	
2,936,231	4,858,196	96,619,468	-536,222	100,941,442	

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2013	Year/Period of Report End of 2012/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.
137,496		7,891,452		7,891,452	1
		6,393		6,393	2
104		20,550		20,550	3
		-9,826		-9,826	4
313		17,342		17,342	5
1,284		33,700		33,700	6
5,785		464,175		464,175	7
		49,900		49,900	8
33		2,314		2,314	9
	1,441	14,049		15,490	10
		-713		-713	11
	2,908			2,908	12
4,622		102,830		102,830	13
30,750		-412,519		-412,519	14
94,158	2,980,357	3,406,753	-536,222	5,850,888	
2,842,073	1,877,839	93,212,715	0	95,090,554	
2,936,231	4,858,196	96,619,468	-536,222	100,941,442	

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2013	Year/Period of Report End of 2012/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.
-42		-1,002		-1,002	1
	29			29	2
4,175		240,868		240,868	3
27		854		854	4
4,591		307,072		307,072	5
1,989		71,299		71,299	6
1,555		58,398		58,398	7
		-217,331		-217,331	8
7,764		450,073		450,073	9
-173,041		-5,399,127		-5,399,127	10
-1,708		-42,634		-42,634	11
7,615		462,709		462,709	12
1,738		-75,454		-75,454	13
		683,407		683,407	14
94,158	2,980,357	3,406,753	-536,222	5,850,888	
2,842,073	1,877,839	93,212,715	0	95,090,554	
2,936,231	4,858,196	96,619,468	-536,222	100,941,442	

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	04/11/2013	End of 2012/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.
		1,442		1,442	1
		14,505		14,505	2
132,252		4,989,606		4,989,606	3
9		287		287	4
606		221,883		221,883	5
-7,845		-219,436		-219,436	6
		53,199		53,199	7
19,685		962,671		962,671	8
					9
		1,518		1,518	10
6,272		223,012		223,012	11
1,985		144,155		144,155	12
10,969	-11	357,424		357,413	13
3,347		176,597		176,597	14
94,158	2,980,357	3,406,753	-536,222	5,850,888	
2,842,073	1,877,839	93,212,715	0	95,090,554	
2,936,231	4,858,196	96,619,468	-536,222	100,941,442	

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	04/11/2013	End of 2012/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.
18,272		1,401,464		1,401,464	1
711,073	1,464,318	17,891,404		19,355,722	2
		-43		-43	3
100		5,888		5,888	4
4,125		286,958		286,958	5
8,541		256,629		256,629	6
-461		-9,578		-9,578	7
-195		-5,110		-5,110	8
1,157		59,513		59,513	9
2,775		132,668		132,668	10
10		513		513	11
		467,244		467,244	12
2,173		155,176		155,176	13
975		32,251		32,251	14
94,158	2,980,357	3,406,753	-536,222	5,850,888	
2,842,073	1,877,839	93,212,715	0	95,090,554	
2,936,231	4,858,196	96,619,468	-536,222	100,941,442	

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	04/11/2013	End of 2012/Q4

SALES FOR RESALE (Account 447) (Continued)

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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)
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MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	REVENUE: Energy Charges ($) (i)	REVENUE: Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
302		17,087		17,087	1
5,949		391,658		391,658	2
1,005		29,713		29,713	3
938		34,491		34,491	4
		-2,309		-2,309	5
-26		-528		-528	6
1,459		89,040		89,040	7
91		6,007		6,007	8
		-51,456		-51,456	9
		-3,402,336		-3,402,336	10
		-136,074		-136,074	11
		69,942		69,942	12
64,272		3,165,192		3,165,192	13
4,162		151,890		151,890	14
94,158	2,980,357	3,406,753	-536,222	5,850,888	
2,842,073	1,877,839	93,212,715	0	95,090,554	
2,936,231	4,858,196	96,619,468	-536,222	100,941,442	

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	04/11/2013	End of 2012/Q4

SALES FOR RESALE (Account 447) (Continued)

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MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
-25		-1,347		-1,347	1
72,088	636	2,517,490		2,518,126	2
5,885		109,661		109,661	3
16,860		1,414,318		1,414,318	4
		48,393		48,393	5
					6
					7
					8
					9
					10
					11
					12
					13
					14
94,158	2,980,357	3,406,753	-536,222	5,850,888	
2,842,073	1,877,839	93,212,715	0	95,090,554	
2,936,231	4,858,196	96,619,468	-536,222	100,941,442	

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	04/11/2013	2012/Q4

FOOTNOTE DATA

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

Amount represents transmission services and related charges.

Schedule Page: 310 Line No.: 2 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.: 4 Column: a

Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company and Ohio Power Company are associated companies and members of the American Electric Power System Pool, whose electric facilities are interconnected at a number of points and are operated in a fully coordinated manner on a system pool basis. Power transactions between the members of the AEP System Pool are governed by the terms of the interconnection agreement dated July 6, 1951, as amended, and are processed by American Electric Power Service.

Schedule Page: 310 Line No.: 5 Column: a

Affiliated company transactions related to the System Integration Agreement. See pages 122-123 (Notes to Financial Statements) Related Party Transactions - System Integration Agreement for additional information.

Schedule Page: 310 Line No.: 6 Column: a

Reclass between 447 and 555 accounts to incorporate certain trading/marketing activity. The amounts represented on pages 310-11 and 326-27 are equal and off-setting.

Schedule Page: 310 Line No.: 7 Column: c

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

Schedule Page: 310.3 Line No.: 6 Column: c

KPCO FERC Electric Tariff Original Vol. No. 2, SA No. 79.

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	04/11/2013	End of 2012/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	2,064,333	3,274,827
5	(501) Fuel	93,157,360	193,705,334
6	(502) Steam Expenses	2,759,155	5,350,951
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	295,080	470,919
10	(506) Miscellaneous Steam Power Expenses	5,519,141	5,019,568
11	(507) Rents		4
12	(509) Allowances	8,873,595	13,421,021
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	112,668,664	221,242,624
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,059,495	2,050,260
16	(511) Maintenance of Structures	573,927	1,229,636
17	(512) Maintenance of Boiler Plant	5,552,809	5,969,199
18	(513) Maintenance of Electric Plant	1,396,877	1,126,660
19	(514) Maintenance of Miscellaneous Steam Plant	617,125	1,007,677
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	10,200,233	11,383,432
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	122,868,897	232,626,056
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)		

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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	247,203,291	249,882,789
77	(556) System Control and Load Dispatching	171,352	320,246
78	(557) Other Expenses	1,458,376	2,263,835
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	248,833,019	252,466,870
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	371,701,916	485,092,926
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	659,388	627,760
84			
85	(561.1) Load Dispatch-Reliability	5,642	5,865
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	764,533	826,362
87	(561.3) Load Dispatch-Transmission Service and Scheduling	-77	4
88	(561.4) Scheduling, System Control and Dispatch Services	1,160,718	1,184,451
89	(561.5) Reliability, Planning and Standards Development	136,890	100,460
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	245,515	272,347
93	(562) Station Expenses	188,431	162,829
94	(563) Overhead Lines Expenses	153,317	155,114
95	(564) Underground Lines Expenses		3,933
96	(565) Transmission of Electricity by Others	4,361,575	3,208,715
97	(566) Miscellaneous Transmission Expenses	1,208,167	1,036,098
98	(567) Rents	2,204	4,809
99	TOTAL Operation (Enter Total of lines 83 thru 98)	8,886,303	7,588,747
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	136,306	145,588
102	(569) Maintenance of Structures	27,527	13,967
103	(569.1) Maintenance of Computer Hardware	44,422	52,859
104	(569.2) Maintenance of Computer Software	204,089	230,750
105	(569.3) Maintenance of Communication Equipment	95,634	211,706
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	564,396	814,617
108	(571) Maintenance of Overhead Lines	2,075,115	1,754,719
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	169,121	21,942
111	TOTAL Maintenance (Total of lines 101 thru 110)	3,316,610	3,246,148
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	12,202,913	10,834,895

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	04/11/2013	End of 2012/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	1,194,322	1,239,747
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	1,194,322	1,239,747
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)	1,194,322	1,239,747
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	665,170	795,830
135	(581) Load Dispatching	2,293	1,805
136	(582) Station Expenses	179,855	203,293
137	(583) Overhead Line Expenses	187,323	897,008
138	(584) Underground Line Expenses	129,749	143,640
139	(585) Street Lighting and Signal System Expenses	100,429	44,684
140	(586) Meter Expenses	519,469	865,238
141	(587) Customer Installations Expenses	129,726	146,018
142	(588) Miscellaneous Expenses	5,407,980	4,292,674
143	(589) Rents	1,682,012	2,055,375
144	TOTAL Operation (Enter Total of lines 134 thru 143)	9,004,006	9,445,565
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	739	47
147	(591) Maintenance of Structures	24,153	8,877
148	(592) Maintenance of Station Equipment	517,533	1,020,000
149	(593) Maintenance of Overhead Lines	30,483,135	33,447,181
150	(594) Maintenance of Underground Lines	92,158	69,503
151	(595) Maintenance of Line Transformers	68,385	120,471
152	(596) Maintenance of Street Lighting and Signal Systems	43,716	62,231
153	(597) Maintenance of Meters	53,792	56,182
154	(598) Maintenance of Miscellaneous Distribution Plant	85,508	139,002
155	TOTAL Maintenance (Total of lines 146 thru 154)	31,369,119	34,923,494
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	40,373,125	44,369,059
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	272,442	324,870
160	(902) Meter Reading Expenses	453,028	691,558
161	(903) Customer Records and Collection Expenses	5,331,906	5,925,504
162	(904) Uncollectible Accounts	152,616	14,449
163	(905) Miscellaneous Customer Accounts Expenses	16,264	87,535
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	6,226,256	7,043,916

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	04/11/2013	End of 2012/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	211,612	329,522
168	(908) Customer Assistance Expenses	2,591,856	2,995,083
169	(909) Informational and Instructional Expenses	155,343	187,054
170	(910) Miscellaneous Customer Service and Informational Expenses	37,709	24,849
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	2,996,520	3,536,508
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	-5	13
175	(912) Demonstrating and Selling Expenses	2	1
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	-3	14
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	6,723,161	5,810,251
182	(921) Office Supplies and Expenses	584,743	551,344
183	(Less) (922) Administrative Expenses Transferred-Credit	1,333,464	1,132,861
184	(923) Outside Services Employed	4,660,005	4,842,138
185	(924) Property Insurance	605,545	641,058
186	(925) Injuries and Damages	1,010,501	1,712,263
187	(926) Employee Pensions and Benefits	5,291,855	5,311,103
188	(927) Franchise Requirements	145,896	190,119
189	(928) Regulatory Commission Expenses	155,946	8,450
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	68,468	70,331
192	(930.2) Miscellaneous General Expenses	290,504	483,880
193	(931) Rents	124,108	126,088
194	TOTAL Operation (Enter Total of lines 181 thru 193)	18,327,268	18,614,164
195	Maintenance		
196	(935) Maintenance of General Plant	1,578,835	1,801,219
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	19,906,103	20,415,383
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	454,601,152	572,532,448

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	04/11/2013	2012/Q4

FOOTNOTE DATA

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.: 76 Column: b

The demand portion of purchased power costs in KPCo's generation formula rates is in a subaccount of FERC account 555 that 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	04/11/2013	End of 2012/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	Adjustment	OS				
3	AEP Service Corporation	OS	20			
4	AEP Service Corporation	OS	11			
5	Ameren Energy Marketing	OS				
6	American Municipal Power - Ohio	OS				
7	Associated Electric Cooperative	OS				
8	J ARON & Company	OS				
9	Barclays Bank PLC	OS				
10	Beech Ridge Energy LLC	OS				
11	BP AMOCO	OS				
12	BP Energy Company	OS				
13	Buckeye Rural Electric Administration	OS				
14	Constellation Energy Commodities	OS				
	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	04/11/2013	End of 2012/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	DP&L Power Services	OS				
2	Duke Energy Carolinas, LLC	OS				
3	Dynergy Power Marketing Inc.	OS				
4	EDF Trading North America LLC	OS				
5	East KY Power Co-Op Power Mktg	OS				
6	Energy America, LLC	OS				
7	Entergy Power Service	OS				
8	Exelon Generation - Power Team	OS				
9	JP Morgan Ventures Energy Corp	OS				
10	LG&E Utilities Power Sales	OS				
11	Midwest ISO	OS				
12	Mizuho Securities USA Inc.	OS				
13	NC Electric Membership Corp.	OS				
14	North Carolina Muni Pwr Agency #1	OS				
	Total					

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2013	Year/Period of Report End of 2012/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.

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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	NextEra Energy Power Mktg LLC	OS				
2	National Power Cooperative Inc.	OS				
3	NRG Power Marketing Inc.	OS				
4	Old Dominion Electric	OS				
5	OVEC Power Scheduling	OS				
6	PJM Interconnection	OS				
7	PJM Environmental Info Sys Inc.	OS				
8	Southern Maryland Elec Coop Inc.	OS				
9	Southern Company	OS				
10	The Energy Authority	OS				
11	TVA Bulk Power Trading	OS				
12	UBS Securities LLC	OS				
13	Wisconsin Electric Power Co.	OS				
14	Wisconsin Power & Light	OS				
	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	04/11/2013	End of 2012/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.

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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	WPPI Energy	OS				
2	Wasbash Valley Power Association Inc.	OS				
3						
4						
5						
6						
7						
8						
9						
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	04/11/2013	End of 2012/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: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
2,817,264			41,126,469	61,244,425		102,370,894	1
				-256,487		-256,487	2
410				11,080		11,080	3
3,995,045			22,446,590	103,279,887		125,726,477	4
			1,607			1,607	5
2,443				109,829		109,829	6
368				10,438		10,438	7
				-10,451		-10,451	8
				66,128		66,128	9
				-10,152		-10,152	10
				-8,556		-8,556	11
				-5,652		-5,652	12
				146,898		146,898	13
15,964			298,457	472,516		770,973	14
7,295,116			64,462,780	182,740,511		247,203,291	

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	04/11/2013	End of 2012/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)	
				9,977		9,977	1
4				334		334	2
			2,764			2,764	3
			5,690			5,690	4
47				1,234		1,234	5
				23,344		23,344	6
271				6,473		6,473	7
				415,135		415,135	8
			18,803			18,803	9
522				22,778		22,778	10
1,697				47,890		47,890	11
				89,646		89,646	12
31				1,200		1,200	13
1				27		27	14
7,295,116			64,462,780	182,740,511		247,203,291	

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	04/11/2013	End of 2012/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)	
				47,879		47,879	1
4,976			21,707	360,563		382,270	2
43				1,531		1,531	3
87				2,920		2,920	4
				-19,894		-19,894	5
417,482			536,315	15,411,974		15,948,289	6
				53		53	7
72				2,360		2,360	8
6				316		316	9
5,098				217,703		217,703	10
33,285				758,682		758,682	11
				288,483		288,483	12
			584			584	13
			2,469			2,469	14
7,295,116			64,462,780	182,740,511		247,203,291	

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	04/11/2013	End of 2012/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)	
			1,324			1,324	1
			1			1	2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
7,295,116			64,462,780	182,740,511		247,203,291	

Name of Respondent Kentucky Power Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2013	Year/Period of Report 2012/Q4

FOOTNOTE DATA

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

An AEP affiliate.

Schedule Page: 326 Line No.: 2 Column: a

Reclass between 447 and 555 accounts to incorporate certain trading/marketing activity. The amounts represented on pages 310-11 and 326-27 are equal and off-setting.

Schedule Page: 326 Line No.: 3 Column: a

Affiliated company - transactions related to the System Integration Agreement. See pages 122-123 (Notes to Financial Statements) Related Party Transactions - System Integration Agreement for additional information.

Schedule Page: 326 Line No.: 4 Column: a

Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company and Ohio Power Company are associated companies and members of the American Electric Power System Power Pool, whose electric facilities are interconnected at a number of points and are operated in a fully coordinated manner on a system pool basis. Power transactions between the members of the AEP System Pool are governed by the terms of the interconnection agreement dated July 6, 1951, as amended, and are processed by American Electric Power Service Corporation.

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	04/11/2013	End of 2012/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 Expansion Cost Recovery - Non Affil	Various	Various	OS
2				FNS
3	PJM Network Integration	Various	Various	
4	Revenue - Affiliated			
5				FNO
6	PJM Network Integration	Various	Various	
7	Revenue - Non Affiliated			
8				FNO
9	PJM Network Integration	Various	Various	
10	Transmission Service - Non Affiliated			
11				LFP
12	PJM Point to Point Transmission	Various	Various	
13	Service - Non Affiliated			
14				OS
15	PJM Power Factor Credits Revenue	Various	Various	
16	Wholesale Customer - Non Affiliated			
17				FNO
18	PJM RTEP Trans Enhancement Revenue	Various	Various	
19	for Wholesale/Formula Rate Cust-Non Affil			
20				FNO
21	PJM Transmission Enhancement	Various	Various	
22	Revenue - Non Affiliated			
23				FNS
24	PJM Transmission Enhancement	Various	Various	
25	Revenue - Affiliated			
26				OLF
27	PJM Transmission Owner Admin	Various	Various	
28	Revenue - Non Affiliated			
29				OLF
30	PJM Transmission Owner Service	Various	Various	
31	Revenue - Affiliated			
32				OLF
33	PJM Transmission Owner Service Rev	Various	Various	
34	Whlsle Customer - Non Affiliated			
	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	04/11/2013	End of 2012/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 Classifi-cation (d)
1	RTO Formation Cost Recovery - Non Affil	Various	Various	OS
2				
3	SECA Transmission Revenue	Various	Various	OS
4				
5	East Kentucky Power Cooperative - Non Affil	Various	Various	OLF
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				
	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	04/11/2013	End of 2012/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 MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
PJM OATT						1
						2
PJM OATT						3
						4
						5
PJM OATT						6
						7
						8
PJM OATT						9
						10
						11
PJM OATT						12
						13
						14
PJM OATT						15
						16
						17
PJM OATT						18
						19
						20
PJM OATT						21
						22
						23
PJM OATT						24
						25
						26
PJM OATT						27
						28
						29
PJM OATT						30
						31
						32
PJM OATT						33
						34
			0	39,376	39,376	

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	04/11/2013	End of 2012/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 MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
						1
PJM OATT						2
						3
PJM OATT						4
				39,376	39,376	5
See footnote						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
			0	39,376	39,376	

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	04/11/2013	End of 2012/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.
85,014			85,014	1
				2
2,972,472			2,972,472	3
				4
				5
2,536,674			2,536,674	6
				7
				8
10,095,090			10,095,090	9
				10
				11
696,676			696,676	12
				13
				14
		8,463	8,463	15
				16
				17
16,753			16,753	18
				19
				20
163,820			163,820	21
				22
				23
17,795			17,795	24
				25
				26
	235,656		235,656	27
				28
				29
	32,423		32,423	30
				31
				32
	36,387		36,387	33
				34
16,594,769	304,466	294,711	17,193,946	

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	04/11/2013	End of 2012/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.
10,475			10,475	1
				2
		227,184	227,184	3
				4
		59,064	59,064	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
16,594,769	304,466	294,711	17,193,946	

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	04/11/2013	2012/Q4

FOOTNOTE DATA

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.: 15 Column: m

Per Proforma ILDSA AEP Tariff 3rd Revised Volume No.6.

Schedule Page: 328.1 Line No.: 3 Column: m

See "Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund" in footnote #2 Rate Matters Notes to Financial Statements. In 2012, a reduction in the reserve for SECA revenues was recorded.

Schedule Page: 328.1 Line No.: 5 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. 1491, the Interconnection Agreement between AEPSC and East Kentucky Power Cooperative.

Schedule Page: 328.1 Line No.: 5 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. 1491, the Interconnection Agreement between AEPSC and East Kentucky Power Cooperative.

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2013	Year/Period of Report End of 2012/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 Tariff (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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2013	End of 2012/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)	TRANSFER OF ENERGY: 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		106,421	106,421			159,632	159,632
2	East KY Power Coop	LFP						
3								
4	PJM	OS					4,201,879	4,201,879
5								
6	Other	OS					64	64
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		106,421	106,421			4,361,575	4,361,575

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	04/11/2013	2012/Q4

FOOTNOTE DATA

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. 1491, the Interconnection Agreement between AEPSC and East Kentucky Power Cooperative.

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

Transmission Enhancement Charges and Credits (PJM OATT Schedule 12)
Network Integration Transmission Service Charges - NITS (PJM OATT Schedule H)

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	04/11/2013	End of 2012/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	104,606
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	2,998
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	8,000
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Associated Business Development	100,169
7	AEP Service Corporation Billings	94,638
8	Intercompany Billings (Net)	-71,443
9	Corporate Money Pool Allocations	13,163
10	Employee Death Benefits	21,200
11	Advertising Expense	5,600
12	Miscellaneous	11,573
13		
14		
15		
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46	TOTAL	290,504

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	04/11/2013	End of 2012/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			2,809,211		2,809,211
2	Steam Production Plant	20,315,422		552,360		20,867,782
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant					
7	Transmission Plant	7,897,690				7,897,690
8	Distribution Plant	22,040,399				22,040,399
9	Regional Transmission and Market Operation					
10	General Plant	830,053		21,322		851,375
11	Common Plant-Electric					
12	TOTAL	51,083,564		3,382,893		54,466,457

B. Basis for Amortization Charges

Section A, Line 1, Column D represents amortization of franchises over the life of the franchise ($521) and amortization of capitalized software development costs over a 5 year life ($2,808,690)

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) = ($217,404)
SCR Catalyst Layer 2 (19 years) = ($171,697)
SCR Catalyst Layer 3 (10 years) = ($163,259)

TOTAL = $(552,360)

Section A, Line 10, Column D represents amortization of Leasehold Improvements over the term of the lease for the respective building

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Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2013	End of 2012/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	538,469					
13	TRANSMISSION PLANT	462,579					
14	DISTRIBUTION PLANT	641,181					
15	GENERAL PLANT	32,507					
16	DEPRECIABLE SUM	1,674,736					
17							
18							
19							
20							
21							
22							
23							
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Name of Respondent Kentucky Power Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2013	Year/Period of Report 2012/Q4

FOOTNOTE DATA

Schedule Page: 336 Line No.: 7 Column: b

Generation Step-Up Units' (GSUs) 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 Line No.: 16 Column: b

The depreciable plant base is the November 30, 2012 total company depreciable plant.

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	04/11/2013	End of 2012/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	Retrofit Big Sandy Unit 2		126,373	126,373	
2	KPSC - Case No. 2011-000401				
3			29,573	29,573	
4	Miscellaneous				
5					
6					
7					
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46	TOTAL		155,946	155,946	

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	04/11/2013	End of 2012/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							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
	928	126,373					1
							2
							3
	928	29,573					4
							5
							6
							7
							8
							9
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		155,946					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	04/11/2013	End of 2012/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	6 Items under $50,000
2		
3	A(1)e: Generation: Unconventional	2 Items under $50,000
4		
5	A(2): Transmission	4 Items under $50,000
6		
7	A(2)a: Transmission: Overhead	1 Item under $50,000
8		
9	A(3): Distribution	1 Item under $50,000
10		Carbon Management - University of Kentucky Research Foundation
11	A(5): Environment (other than equipment)	Industrial Advisory Committee - Southern Company
12		3 Items under $50,000
13		
14		6 Items under $50,000
15	A(6): Other	
16		1 Item under $50,000
17	A(6)f: Other (metering)	
18		
19	A(7) Total costs incurred internally	
20		
21		EPRI Environmental Science
22	B(1): R&D support to the Research Council	EPRI Research Portfolio
23	or the Electric Power Research	80 Items under $50,000
24	Institute	
25		5 Items under $50,000
26	B(4): Research support to others	
27		
28	B(5) Total costs incurred externally	
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		

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	04/11/2013	End of 2012/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.
					1
8,093		506	8,093		2
					3
3,231		506, 588	3,231		4
					5
2,299		566	2,299		6
					7
9		566	9		8
					9
11		588	11		10
					11
200,000		182.3	200,000		12
78,229		506	78,229		13
852		506	852		14
					15
9,021		Various	9,021		16
					17
6		588	6		18
					19
301,751			301,751		20
					21
					22
	124,193	506	124,193		23
	88,327	Various	88,327		24
	127,723	Various	127,723		25
					26
	17,544	566, 588	17,544		27
					28
	357,787		357,787		29
					30
					31
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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	04/11/2013	End of 2012/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	4,145,232		
4	Transmission	428,641		
5	Regional Market			
6	Distribution	3,258,825		
7	Customer Accounts	1,172,657		
8	Customer Service and Informational	513,608		
9	Sales			
10	Administrative and General	701,517		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	10,220,480		
12	Maintenance			
13	Production	4,522,331		
14	Transmission	724,028		
15	Regional Market			
16	Distribution	5,135,710		
17	Administrative and General	685,959		
18	TOTAL Maintenance (Total of lines 13 thru 17)	11,068,028		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	8,667,563		
21	Transmission (Enter Total of lines 4 and 14)	1,152,669		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	8,394,535		
24	Customer Accounts (Transcribe from line 7)	1,172,657		
25	Customer Service and Informational (Transcribe from line 8)	513,608		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	1,387,476		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	21,288,508	1,146,887	22,435,395
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	04/11/2013	End of 2012/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)	21,288,508	1,146,887	22,435,395
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	10,932,997	588,999	11,521,996
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	10,932,997	588,999	11,521,996
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,414,791	130,093	2,544,884
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	2,414,791	130,093	2,544,884
77	Other Accounts (Specify, provide details in footnote):			
78	152 - Fuel Stock Undistributed	1,178,655		1,178,655
79	163 - Stores Expense Undistributed	1,032,522	-1,032,522	
80	183 - Prelim Survey	9,795	-9,795	
81	184 - Clearing Accounts	823,662	-823,662	
82	185 - ODD Temporary Facilities	32,859		32,859
83	186 - Misc Deferred Debits	520,053		520,053
84	188 - Research & Development	-736		-736
85	426 - Political Activities	34,689		34,689
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	3,631,499	-1,865,979	1,765,520
96	TOTAL SALARIES AND WAGES	38,267,795		38,267,795

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	04/11/2013	2012/Q4

FOOTNOTE DATA

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	04/11/2013	End of 2012/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	04/11/2013	End of 2012/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)				4,586,566
3	Net Sales (Account 447)				(13,744,531)
4	Transmission Rights				(776,228)
5	Ancillary Services				285,411
6	Other Items (list separately)				
7	Congestion				1,064,018
8	Operating Reserves				(520,732)
9	Transmission Purchase Expense				140,585
10	Transmission Losses				2,694,954
11	Meter Corrections				39,321
12	Inadvertent				7,707
13	Capacity Credits				(61,789)
14	Miscellaneous				
15					
16					
17					
18					
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46	TOTAL				(6,284,718)

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	04/11/2013	End of 2012/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)						

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

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.

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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									

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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/RTD (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	04/11/2013	End of 2012/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	2,661,344
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)	2,661,344
10	Purchases	7,295,116
11	Power Exchanges:	
12	Received	
13	Delivered	
14	Net Exchanges (Line 12 minus line 13)	
15	Transmission For Other (Wheeling)	
16	Received	39,376
17	Delivered	39,376
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)	9,956,460

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	6,660,656
23	Requirements Sales for Resale (See instruction 4, page 311.)	94,158
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,842,073
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
27	Total Energy Losses	359,573
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	9,956,460

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	04/11/2013	End of 2012/Q4

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 (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	910,405	184,824	1,378	4	800
30	February	789,272	147,447	1,340	13	800
31	March	667,402	108,821	1,247	6	800
32	April	794,967	274,729	1,071	12	700
33	May	697,364	143,048	1,066	3	1300
34	June	789,801	235,915	1,183	29	1600
35	July	1,035,341	442,533	1,182	26	1600
36	August	1,001,519	421,287	1,138	8	1600
37	September	748,209	244,103	1,050	5	1600
38	October	793,473	251,401	1,046	29	1900
39	November	767,788	156,852	1,203	29	800
40	December	960,919	320,498	1,213	13	800
41	TOTAL	9,956,460	2,931,458			

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Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2013	End of 2012/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: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	STEAM					
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	CONVENTIONAL					
3	Year Originally Constructed	1963					
4	Year Last Unit was Installed	1969					
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	1096.80			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	1083			0		
7	Plant Hours Connected to Load	5462			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	1078			0		
10	When Limited by Condenser Water	1078			0		
11	Average Number of Employees	124			0		
12	Net Generation, Exclusive of Plant Use - KWh	2661344000			0		
13	Cost of Plant: Land and Land Rights	1076546			0		
14	Structures and Improvements	43159343			0		
15	Equipment Costs	503622784			0		
16	Asset Retirement Costs	3614563			0		
17	Total Cost	551473236			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	502.8020			0		
19	Production Expenses: Oper, Supv, & Engr	2064333			0		
20	Fuel	88366983			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	2759155			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	295080			0		
26	Misc Steam (or Nuclear) Power Expenses	5519141			0		
27	Rents	0			0		
28	Allowances	8873595			0		
29	Maintenance Supervision and Engineering	2059495			0		
30	Maintenance of Structures	573927			0		
31	Maintenance of Boiler (or reactor) Plant	5552809			0		
32	Maintenance of Electric Plant	1396877			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	617125			0		
34	Total Production Expenses	118078520			0		
35	Expenses per Net KWh	0.0444			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil				
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels				
38	Quantity (Units) of Fuel Burned	1139610	24837	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11992	137344	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	80.862	132.305	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	74.684	131.129	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.114	22.732	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.032	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	10324.000	0.000	0.000	0.000	0.000	0.000

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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: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	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	0	0	21
0	0	0	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
			36

(d)			(e)			(f)			Line No.
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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	0.00	0.00
5	Total Installed cap (Gen name plate Rating in MW)	0	0
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load		
8	Net Plant Capability (in megawatts)	0	0
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		
13	Cost of Plant	0	0
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)	0.0000	0.0000
21	Cost per KW of Installed Capacity (line 20 / 5)		
22	Production Expenses	0	0
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)	0.0000	0.0000
35	Expenses per net KWh		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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 Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2013	Year/Period of Report End of 2012/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
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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.
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			24
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			36
			37
			38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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						
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3						
4						
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45						
46						

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2013	Year/Period of Report End of 2012/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
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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	04/11/2013	End of 2012/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 Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(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	6.75		1
18	0103 HAZARD, KY	BEAVER CREEK, KY	138.00	138.00	ST	22.35		1
19	0105 CLINCH RIVER, VA	BEAVER CREEK, KY	138.00	138.00	ST	1.47		1
20	0105 CLINCH RIVER, VA	BEAVER CREEK, KY	138.00	138.00	WP	16.92	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
					TOTAL	1,241.03	40.50	49
36								

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	04/11/2013	End of 2012/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 From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of 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	7.64		1
4	0108 BEAVER CREEK	SPRIGG #1	138.00	138.00	WP	32.60		1
5	0124 BIG SANDY	SOUTH NEAL	138.00	138.00	WP	0.01		1
6	0109 BEAVER CREEK	SPRIGG #3	138.00	138.00				
7	0125 BELLEFONTE	AK STEEL OXYGEN PLANT	138.00	138.00	ST	0.22		2
8	0130 JOHNS CREEK	SPRIGG	138.00	138.00	ST	13.00		
9	0131 BAKER	BIG SANDY EXT.	138.00	138.00	ST	1.00		1
10	0128 INEZ	JOHNS CREEK	138.00	138.00	ST	17.00		
11	0129 BEAVER CREEK	JOHNS CREEK	138.00	138.00	ST	22.00		
12	0132 GRANGSTON LOOP		138.00	138.00				
13	0137 HAYS BRANCH	MORGAN FORK	138.00	138.00	ST	8.30		1
14	0138 SOFT SHELL	BEAVER CREEK	138.00	138.00	ST	1.40		2
15	0138 SOFT SHELL	SPICEWOOD	138.00	138.00	ST	1.40		2
16	0139 MORGAN FORK	BETSY LANE	138.00	138.00	ST	0.10		1
17	0139 MORGAN FORK	BEAVER CREEK	138.00	138.00	ST	0.10		1
18								
19	LINES < 132KV		69.00	69.00		595.11	6.16	
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	1,241.03	40.50	49

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	04/11/2013	End of 2012/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)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
954 MCMA	258	10,045	10,303					1
954 MCMA	295,039	6,252,403	6,547,442					2
								3
954 MCMA	2,473,694	25,856,054	28,329,748					4
								5
								6
351.5 VAR	13,500,178	109,355,527	122,855,705	30,843	417,458		448,301	7
954 MCMA	119,991	1,208,955	1,328,946	1,000	13,537		14,537	8
500 MCMCU	62,481	3,647,457	3,709,938					9
								10
795 MCM 26/7	69,669		69,669					11
795 MCM 26/7		194,639	194,639	5,674	76,801		82,475	12
556.5 VAR	377,782	2,299,556	2,677,338					13
								14
1033.5 VAR	8,028	64,567	72,595					15
397.5 MA		126,299	126,299					16
397.5 MCMCU	59,684	7,123,552	7,183,236					17
								18
636 MCMA	84,068	1,599,018	1,683,086					19
								20
397 MCMA	156	446,241	446,397					21
397.5 MCMA	309,219	3,078,326	3,387,545					22
								23
								24
795 MCMA	12,053	631,930	643,983					25
								26
795 MCMA	50,579	268,040	318,619					27
795 MCMA	248,782	465,602	714,384					28
	67,982	914,472	982,454					29
556.5 MCM	408,729	65,248	473,977					30
795 MCMA	555,042	2,823,053	3,378,095					31
1590 KCM								32
1033 MCM		1,506,763	1,506,763					33
10335 VAR	631,057	4,454,771	5,085,828					34
10335 VAR	2,783	571,688	574,471					35
	27,829,358	285,029,408	312,858,766	153,317	2,075,115		2,228,432	36

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	04/11/2013	End of 2012/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)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
10335 VAR	2,269	56,174	58,443					1
795 MCMA	1,183,715	12,705,933	13,889,648					2
795 MCMA	150,919	1,240,544	1,391,463					3
397 MCMA	98,056	918,631	1,016,687					4
10335 VAR		116,738	116,738					5
	51,485		51,485					6
795 ACSR	1,393	225,286	226,679					7
1033 MCM		3,833,913	3,833,913					8
1351 KCM	650	1,179,194	1,179,844					9
2-556.5 MCM	946,443	9,965,916	10,912,359					10
1033 MCM	195,162	7,528,044	7,723,206					11
	4,103	1	4,104					12
795 ACSR	1,363,522	9,438,072	10,801,594					13
1590 ACSR	189,560	3,683,444	3,873,004					14
1590 ACSR								15
795 ACSR		526,313	526,313					16
795 ACSR				43,866	593,714		637,580	17
								18
	4,304,827	60,646,999	64,951,826	71,934	973,605		1,045,539	19
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								35
	27,829,356	285,029,408	312,858,766	153,317	2,075,115		2,228,432	36

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	04/11/2013	End of 2012/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 From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	NO LINES ADDED						
2							
3	NO LINES ALTERED						
4							
5							
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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	04/11/2013	End of 2012/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 KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
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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	04/11/2013	End of 2012/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	ASHLAND-KY	D	69.00	12.00	
2		D	69.00		
3	BAKER-KY	T	765.00		
4		T	765.00	345.00	34.50
5		T	345.00	138.00	34.50
6		T	138.00	34.50	
7		T	69.00	12.00	
8		T	69.00	12.00	
9		T	69.00	4.00	
10	BARRENSHE-KY	D	69.00	12.00	
11	BEAVER CREEK-KY	T	138.00	69.00	46.00
12		T	138.00	34.50	
13		T	138.00	8.30	
14		T	138.00		
15		T	138.00		
16	BECKHAM-KY	D	138.00	34.50	
17		D	138.00		
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-KY	T	138.00	69.00	34.50
22		T	138.00	35.00	
23		T	138.00	13.09	
24		T	69.00		
25	BETSY LAYNE-KY	T	138.00	69.00	46.00
26		T	138.00	34.00	
27		T	46.00	12.00	
28		T	46.00		
29	BIG SANDY 138KV-KY	T	138.00	69.50	13.20
30		T	138.00	34.50	
31		T	138.00	13.09	
32	BLUE GRASS-KY	D	69.00	12.00	
33	BONNYMAN-KY	T	69.00	34.50	
34	BUSSEYVILLE-KY	D	138.00	34.50	
35	CANNONSBURG-KY	D	69.00	34.50	
36	CEDAR CREEK-KY	T	138.00	69.00	46.00
37		T	138.00	34.50	
38		T	46.00	7.20	
39		T	34.50	12.00	
40	CHADWICK-KY	T	138.00	69.00	34.50

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Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2013	End of 2012/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	COALTON-KY	D	69.00	12.00	
2		D	69.00		
3	COLEMAN-KY	D	69.00	34.50	
4		D	69.00	12.00	
5	COLLIER-KY	D	69.00	34.00	
6		D	69.00		
7	DEWEY-KY	T	138.00	69.00	12.00
8		T	138.00	34.50	
9		T	69.00		
10	DORTON-KY	T	138.00	46.00	
11	DRAFFIN-KY	D	46.00	12.00	
12	EAST PRESTONSBURG-KY	D	46.00	12.00	
13	ELKHORN CITY-KY	T	69.00	46.00	
14		T	69.00	12.00	
15		T	69.00		
16	ELWOOD (KP)-KY	D	46.00	34.50	6.50
17		D	46.00		
18	ENGLE-KY	D	69.00	34.50	
19	FALCON-KY	D	69.00	46.00	
20		D	69.00	12.00	
21	FEDS CREEK-KY	D	69.00	12.00	
22	FLEMING-KY	T	138.00	69.00	46.00
23		T	69.00	12.00	
24		T	69.00		
25	FORDS BRANCH-KY	D	46.00	34.50	12.00
26		D	46.00		
27	FORTY SEVENTH STREET-KY	D	69.00	13.09	
28	GARRETT (KP)-KY	T	46.00	12.00	
29	GRAYSON-KY	D	69.00	12.00	
30	HADDIX-KY	D	69.00	34.50	
31	HATFIELD (KP)-KY	T	138.00	69.00	46.00
32	HAZARD-KY	T	161.00	138.00	11.00
33		T	138.00	69.00	12.00
34		T	138.00	34.00	
35		T	138.00		
36		T	69.00		
37		T	34.50	12.00	
38	HENRY CLAY-KY	D	46.00	34.50	
39		D	46.00		
40	HIGHLAND (KP)-KY	D	69.00	13.09	

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	04/11/2013	End of 2012/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	HITCHINS-KY	D	69.00	13.09	
2	HOODS CREEK-KY	D	69.00	12.00	
3	HOWARD COLLINS-KY	D	69.00	12.00	
4	INEZ-KY	T	138.00	69.00	13.09
5		T	138.00	37.27	13.80
6		T	138.00	37.00	
7		T	138.00		
8		T	138.00		
9		T	69.00		
10		T	26.00		
11		T	26.00	18.60	
12	JACKSON-KY	D	69.00	12.00	
13		D	69.00		
14	JENKINS-KY	D	69.00	12.00	
15	JOHNS CREEK-KY	T	138.00	69.00	34.00
16		T	138.00		
17		T	69.00		
18	KANAWHA RIVER-KY	D	46.00		
19		D	46.00	12.00	
20	KEYSER-KY	D	69.00	12.00	
21	LESLIE-KY	T	161.00	69.00	12.00
22		T	69.00		
23	LOUISA-KY	D	34.50	12.00	
24	LOVELY-KY	D	138.00	34.00	
25	MAYKING-KY	D	69.00	12.00	
26	MAYO TRAIL-KY	D	69.00	12.00	
27	MCKINNEY-KY	D	46.00	34.00	
28		D	34.50	12.00	
29	NEW CAMP-KY	D	69.00	12.00	
30	OLIVE HILL-KY	D	69.00	12.00	
31		D	69.00	4.00	
32	PIKEVILLE-KY	D	69.00	12.00	
33	PRESTONSBURG-KY	D	46.00	13.09	
34		D	46.00		
35	PRINCESS-KY	D	69.00	34.50	
36		D	69.00		
37	REEDY COAL-KY	D	69.00	34.00	
38	RUSSELL-KY	D	69.00	12.00	
39	SALISBURY (KP)-KY	D	46.00	13.09	
40	SHAMROCK-KY	D	69.00	34.50	

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	04/11/2013	End of 2012/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	SIDNEY-KY	D	69.00	12.00	
2	SLEMP-KY	D	69.00	34.50	
3		D	69.00	34.00	
4	SOFT SHELL-KY	D	138.00	34.50	
5	SOUTH PIKEVILLE-KY	D	69.00	12.00	
6	STINNETT-KY	D	161.00	34.50	7.20
7		D	161.00	34.00	7.20
8	STONE-KY	T	138.00	69.00	46.00
9	TENTH STREET-KY	D	69.00	13.09	
10	THELMA-KY	T	138.00	69.00	46.00
11		T	138.00	69.00	12.00
12		T	138.00		
13		T	46.00		
14	TOM WATKINS-KY	D	69.00	12.00	
15	TOPMOST-KY	D	138.00	13.09	
16	VICCO-KY	D	138.00	34.50	
17	WEST PAINTSVILLE-KY	D	69.00	12.00	
18	WHITESBURG-KY	D	69.00	12.00	
19		D	69.00		
20	WURTLAND-KY	D	69.00	12.00	
21					
22	29 STATIONS UNDER 10 MVA	T/D			
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
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35					
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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	04/11/2013	End of 2012/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.
						1
22	1		STATCAP	1	16	2
			REACTOR	2	200	3
						4
1500	3					5
672	1					6
30		1				7
11		1				8
3		1				9
3	1					10
25	1					11
146	2					12
30	1					13
125	1	1	STATCAP	4	235	14
			SVS	1		15
						16
30	1		STATCAP	1	43	17
						18
20	1					19
11	1					20
20	1					21
308	2					22
45	1					23
22	1		STATCAP	1	14	24
						25
50	1					26
25	1					27
6	1		STATCAP	1	10	28
						29
129	1					30
20	1					31
20	1					32
11	1					33
25	1					34
55	2					35
25	1					36
90	1					37
30		1				38
2		3				39
4		2				40
200	1					

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	04/11/2013	End of 2012/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.
						1
25	1		STATCAP	1	23	2
						3
20	1					4
4	1					5
25	1		STATCAP	1	10	6
						7
90	1					8
25	1		STATCAP	1	27	9
						10
45	1					11
11	1					12
20	1					13
20	1					14
11	1		STATCAP	1	14	15
						16
25	1		STATCAP	1	14	17
						18
20	1					19
20	1					20
20	1					21
22	1					22
130	1					23
20	1		STATCAP	1	14	24
						25
30	1		STATCAP	1	10	26
						27
20	1					28
11	1					29
20	1					30
25	1					31
60	1					32
135	3	1				33
180	2					34
30	1		STATCAP	1	32	35
			STATCAP	2	68	36
						37
8	1					38
30	1		STATCAP	1	10	39
						40
25	1					

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	04/11/2013	End of 2012/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.
25	1					1
11	1					2
31	2					3
50	1					4
160	1					5
320	2					6
			STATCAP	2	106	7
			UPFC	1		8
			STATCAP	1	10	9
86	1					10
86	1					11
15	2					12
			STATCAP	1	10	13
11	1					14
90	1					15
			STATCAP	1	53	16
			STATCAP	1	10	17
			STATCAP	1	7	18
20	1					19
20	1					20
90	1					21
			STATCAP	1	14	22
10	2					23
30	1					24
20	1					25
25	1					26
20	1					27
7	1					28
20	1					29
8	1					30
5	1					31
25	1					32
10	1					33
			STATCAP	1	10	34
20	1					35
			STATCAP	1	22	36
20	1					37
22	1					38
20	1					39
11	1					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	04/11/2013	End of 2012/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.
						1
20	1					2
11	1					3
20	1					4
30	1					5
25	1					6
22	1	1				7
15	1					8
50	1					9
50	2					10
70	1					11
90	1		STATCAP	1	32	12
			STATCAP	1	7	13
						14
11	1					15
20	1					16
30	1					17
25	1	1				18
36	2		STATCAP	1	13	19
						20
20	1					21
						22
156	28					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) 04/11/2013	Year/Period of Report End of 2012/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 - Operation	AEPSC	Various	2,180,738
3	Assets & Other Debits - Current and Accrued Assets	APCo	152, 163	304,573
4	Assets & Other Debits - Utility Plant	APCo	107, 108	640,057
5	Assets & Other Debits - Utility Plant	OPCo	107, 108	333,427
6	Central Machine Shop	APCo	Various	277,178
7	Construction Services	AEPSC	107, 108	10,485,406
8	Corporate Accounting	AEPSC	920	1,096,489
9	Corporate Planning and Budgeting	AEPSC	920	615,740
10	Customer Accounts Expenses	AEPSC	Various	4,626,841
11	Distribution Expenses - Maintenance	OPCo	Various	359,885
12	Distribution Expenses - Operation	AEPSC	Various	1,546,270
13	Emission Allowance Purchases	APCo	158.1	1,062,187
14	Emission Allowance Purchases	OPCo	158.1	5,033,939
15	Environmental Safety Health Facilities	AEPSC	920	293,749
16	Factored Customer A/R Bad Debts	AEP Credit	426.5	1,569,927
17	Factored Customer A/R Expense	AEP Credit	426.5	886,846
18	Fleet and Vehicle Charges	APCo	Various	673,449
19	Fuel & Storeroom Services	AEPSC	151, 152, 163	814,665
20	**Non-power Goods or Services Provided for Affiliate**			
21	Assets & Other Debits - Deferred Debits	OPCo	184, 186, 188	700,819
22	Assets & Other Debits - Utility Plant	APCo	107, 108	801,513
23	Assets & Other Debits - Utility Plant	OHTCo	107, 108	366,428
24	Assets & Other Debits - Utility Plant	OPCo	107, 108	718,567
25	Distribution Expenses - Maintenance	APCo	Various	263,867
26	Fleet and Vehicle Charges	APCo	Various	425,911
27	Materials and Supplies	APCo	Various	2,773,904
28	Materials and Supplies	OPCo	Various	2,488,885
29	Power Production - Steam Power Gen - Maintenance	APCo	510, 512, 513	263,049
30	Transmission Expenses - Maintenance	APCo	Various	545,449
31	Building and Property Leases	AEPSC	454	259,050
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
1	Non-power Goods or Services Provided by Affiliated			
2	Human Resources	AEPSC	923	665,151

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2013	Year/Period of Report End of 2012/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	Information Technology	AEPSC	923	1,844,472
4	Material and Supplies	APCo	Various	1,155,567
5	Material and Supplies	OPCo	Various	590,626
6	Other Power Generation - Maintenance	AEPSC	Various	1,628,674
7	Real Estate & Workplace Services	AEPSC	923	283,917
8	Regulatory Services	AEPSC	920	594,760
9	Research and Other Services	AEPSC	Various	585,942
10	Steam Power Generation - Maintenance	AEPSC	Various	922,233
11	Steam Power Generation - Operation	AEPSC	Various	1,849,994
12	Transmission Expenses - Maintenance	AEPSC	Various	465,607
13	Transmission Expenses - Operation	AEPSC	Various	2,041,396
14	Urea	OPCo	154	1,163,029
15	Legal GC/Administration	AEPSC	920	532,009
16				
17				
18				
19				
20	Non-power Goods or Services Provided for Affiliate			
21				
22				
23				
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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	04/11/2013	2012/Q4

FOOTNOTE DATA

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 formulae 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.: 2 Column: c
920,921,923-926,928,930.1,930.2,931

Schedule Page: 429 Line No.: 6 Column: c
107,108,506,512,513

Schedule Page: 429 Line No.: 10 Column: c
901-905

Schedule Page: 429 Line No.: 11 Column: c
592-595,597,598

Schedule Page: 429 Line No.: 12 Column: c
580-582,584,586,588,589

Schedule Page: 429 Line No.: 18 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.: 25 Column: c
591-595

Schedule Page: 429 Line No.: 27 Column: c
107,108,152,154,163,184,506,511-514,570,571,583,586-588,592-596,598,935

Schedule Page: 429 Line No.: 28 Column: c
107,154,163,511-513,562,566,570,571,583,585,586,588,592-595,902,903,935

Schedule Page: 429 Line No.: 30 Column: c
569-571,573

Schedule Page: 429.1 Line No.: 4 Column: c
107,108,154,186,510-514,570,573,592,593,595,935

Schedule Page: 429.1 Line No.: 5 Column: c
107,154,163,186,511-513,570,571,583,588,592,935

Schedule Page: 429.1 Line No.: 6 Column: c
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183,184,186,188

Schedule Page: 429.1 Line No.: 10 Column: c
510-514

Schedule Page: 429.1 Line No.: 11 Column: c
500-502,506

Schedule Page: 429.1 Line No.: 12 Column: c
568,569,569,569.1-569.3,570,571,573

Schedule Page: 429.1 Line No.: 13 Column: c
560,561.1-561.3,561.5,562,563,566,567

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